ALBERTA NATURAL GAS ROYALTY

Principles and Procedures

Effective January 1, 2000

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ALBERTA NATURAL GAS ROYALTY

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1. Principles and Procedures Manual Overview

1.1 Authority and Scope

The ***Principles, Procedures and the Appendices*** (referred to as the Guidelines) described in this manual are the result of extensive discussion and effort between representatives of both the Alberta Department of Resource Development (the **Department***) and of the petroleum and **natural gas*** industry (**Industry***). The **Regulation*** relating to this manual is the **"Natural Gas Royalty Regulation, 1994"** ***(Alberta Regulation 351/93).***

The ***Alberta Natural Gas Royalty Principles and Procedures*** manual interprets the relevant energy legislation *(statutes and regulations)* and communicates policy decisions made based on the legislation.

The Alberta Department of Resource Development's ***advance ruling**** *process (see Section 12.1)* interprets the manner in which the relevant legislation, policies and guidelines will apply to proposed business arrangements.

This manual describes the ***principles*** involved in assessing, levying and collecting Alberta's Crown royalty share of **gas*** and **gas products*** produced from lands subject to a **Crown lease*** agreement. It also describes the ***procedures*** that will be used to carry out the assessment, levy and collection. Certain associated programs previously managed separately from Crown natural gas royalty are included in the overall gas royalty process as of January 1, 1994. These are:

- Crown Gas Royalty Holidays;
- **Sulphur Emission Control Assistance Program (SECAP)***;
- **Compensatory Royalty***;
- **Trespass Damages***; *and*
- **Field Condensate*** Royalty (*see Section 8.1*).

1.2 Purpose and Use

This manual is designed to be used as:

- a *business reference,* to assist Alberta's petroleum and natural gas industry in their evaluation and decision-making processes;
- a *practical guide to reporting and compliance* with business rules and procedures associated with the assessment, levy and collection of Crown natural gas royalty.

Sections 1-27 and the *Appendices* are written sequentially and are cross-referenced for ease of use. The contents of these are as follows:

- *Sections 1-3* deal with the overview of the Guidelines.
- *Sections 4-13* deal with the principles and policies involved in assessing, levying and collecting Alberta's Crown royalty share of gas and gas products produced from lands subject to Crown's lease agreement.
- *Sections 14-26* deal with the procedures that will be used in assessing, levying and collecting the Crown royalties.
- *Section 27* is a reporting guide for natural gas liquids.
- The *Appendices* deal with sundry items for the information of the royalty clients. It includes various calculations, rules, definitions and other administrative information to assist the royalty clients. ***Please refer to Appendix P for the various forms referred to throughout the Guidelines.***

****For definition, please see Appendix N - Glossary.***

The ***Table of Contents*** is extensive and should permit easy reference to specific business principles and policies. The ***relevant legislation*** is referenced on the left margin, and will direct the user to the pertinent section of legislation. All the words in the *Glossary (Appendix N)* are marked by bold letters and a star (*) the first time they appear in the Guidelines.

Where there is a conflict between the *Principles* and the *Procedures*, the *Principles* prevail; and where there is a conflict between the *Principles* and the *Regulation*, the *Regulation* prevails.

If the *Principles and Procedures* manual does not provide an answer, questions should be directed to the Client Services Help Desk {phone: (780) 427-2962} or the agencies listed in Appendix L.

1.3 Maintenance and Distribution

The Department will update the ***Principles and Procedures*** manual when there is a major change in relevant policy or legislation, and routinely, to incorporate information published in *Information Letters* and *Information Bulletins*.

Information Letters are sent to **Royalty Clients*** each month to provide notification of:

- **Reference Prices***, Par Prices and other Crown natural gas royalty factors;
- changes in legislation and policy; *and*
- interpretations and other information relevant to Crown royalty programs.

Information Bulletins are sent to Royalty Clients each month to provide notification of:

- changes in procedures;
- filing dates *(and reminders)* and interest rates; *and*
- general information relating to the ongoing administration of Crown natural gas royalty.

Royalty clients, or other persons directly affected by the administration of Alberta Crown natural gas royalty, who wish to receive copies of *Information Letters, Information Bulletins* or additional copies of this manual should contact the Client Services Help Desk {phone: (780) 427-2962 or fax: (780) 427-3334 or 422-8732}, or the address provided in *Appendix L.*

The Information Letters, Information Bulletins and other related Gas Royalty information is available on the internet at website address:

http://www.resdev.gov.ab.ca/room/updates/index.htm

****For definition, please see Appendix N - Glossary.***

2. Executive Overview

2.1 Background

In 1991, the Department organized a *Joint Project Team* with recognized petroleum and natural gas industry associations to address the simplification of Crown natural gas royalty administration. The Joint Project Team worked extensively with representatives of many sectors of the petroleum and natural gas industry, chiefly through the following industry associations:

- Canadian Association of Petroleum Producers *(CAPP), formerly*
  - Canadian Petroleum Association *(CPA), and*
  - Independent Petroleum Association of Canada *(IPAC)*;
- Small Explorers and Producers Association of Canada *(SEPAC); and*
- Canadian Association of Petroleum Production Accountants *(CAPPA)*.

The Joint Project Team worked with employees from more than 30 royalty clients to research and develop the Crown Natural Gas Royalty Principles and Procedures that are described in this manual.

2.2 Synopsis of Business Change

Much of the complexity of the pre-1994 Crown natural gas royalty administration was created by the requirement to relate individual sales contracts and **facility**[*] costs to the **Crown interest share**[*] of **well event**[*] production. Retroactive changes to valuation, cost and production data resulted in extensive industry refiling and, as a consequence, closing the Crown natural gas royalty accounts for a given production year could take up to four years.

To address the complexity in administration, the Joint Project Team developed the following major changes to be implemented effective 1994.

- *Crown royalty liability* is triggered at the ***plant gate***[*] *(except where gas is sold prior to processing)*. Existing Crown royalty inventories of gas and gas products are valued and charged to the responsible royalty clients.
- *Crown royalty credits* are established to defer the liability arising from qualified gas and gas product injection. Existing Crown **royalty paid banks**[*] are reverted to native status *(for Crown royalty purposes only)*.
- *Monthly Reference Prices* are used to value the Crown's royalty share of gas *(**raw gas**[*], **residue gas**[*] and **ethane**[*])*, **propane**[*], **butane**[*] and **pentanes-plus**[*]; however, royalty clients may *elect* to value their Crown royalty *gas at an annual **Corporate Average Price**[*]*.
- ***Monthly and Annual Sulphur Corporate Average Price (S-CAP)***[*] *is used to value* ***sulphur***[*]*; however, in certain circumstances, sulphur is valued monthly and annually at Sulphur Default Price.*
- *The Crown's share of the operating costs* of compressing, **gathering**[*] and processing natural gas is recognized through a *Standard Operating Cost* as a rate per **unit**[*] . The ***unit operating cost rates***[*] *(UOCR)* are determined annually.
- *Crown's share of Capital Costs* and ***Crown Share of Custom Processing Fees***[*] *paid* are recognized based on the experience of each individual royalty client.
- The Department issues monthly ***invoices*** to royalty clients in respect of Crown natural gas and natural gas product royalties.

[*] ***For definition, please see Appendix N - Glossary.***

3. Alberta Natural Gas Royalty Process In Summary

3.1 Overview

The Crown gas royalty process can be separated into four distinct groups of submissions:

- ***Once Only***—those through which a royalty client may elect a valuation method.
- ***As Required***—typically those that establish production and cost allocation or accountability for Crown royalty.
- ***Annual***—those that relate to establishing costs, corporate average prices for gas (CAP) and sulphur (S-CAP), or special conditions under the Gas Reference Price.
- ***Monthly***—those from which the monthly Reference Prices are calculated and the Crown's royalty share of gas and gas product volumes/quantities is determined. Monthly submissions are also used to determine monthly Sulphur Corporate Average Price and monthly Sulphur Default Price.

A summary description of the reports in each group is provided in *Section 3.2 (following)* and a graphic overview of the relationship of these reports to the Crown royalty invoice is provided in *Section 3.3.*

3.2 Industry Reporting to the Department *(Refer to the chart on Page 3-3.)*

Group 1 ...Once Only submissions

There are *two forms* in this reporting group. Both are filed by royalty clients.

- The first, *"Election for Gas Valuation" (VA1 form),* is a royalty client's election to value the Crown royalty share of gas at either Reference Price or Corporate Average Price. For persons registered as royalty clients prior to 1994, the due date of the VA1 form was on or before June 15, 1994. For persons who became registered as royalty clients after 1993, the due date of the VA1 form is on or before the 15th day of the second month following the **production month*** in which new royalty clients were first **allocated volumes*** either through the **OAS*** or RMF2 forms. Only clients that have elected **CAP*** may subsequently use the VA1 form to change their election to Reference Price.
- The second, *"Application to Grandfather Co-Generation* or Other Long Term Contracts" (GR1 form),* which applies to Reference Price filers only, is a royalty client's election to grandfather the pricing provisions of co-generation or other **long-term contracts***. The form was due on or before June 15, 1994, and there is no further right to elect thereafter.

Group 2 ...As Required submissions

Of the four forms in this group, only *"Reassignment of Volumes Setup/Change" (RMF2 form)* is filed by royalty clients. It advises the Department of re-allocations of Crown royalty responsibility. The other three forms are filed by Facility **Operators*** to setup/change Consolidated Single Well Groups *(RMF1 form)*, Non-consolidated Single Well Groups and **Injection Schemes*** *(RMF3 form)*, and **Facility Cost Centres*** *(AC1 form)*.

Exhibit A*, which is part of the Unit Agreement, is sent by the Unit Operators to the Crown Equity Group of Mineral Operations Division. This is sent either with the new Unit Agreement or when changes in the Unit Ownership take place.

****For definition, please see Appendix N - Glossary.***

Group 3 …Annual submissions

There are nine forms in this group. The following five forms are filed by royalty clients:

- two to report the calculation of Corporate Average Prices *(gas on the VA2 form, sulphur on the VA3 form)*;
- one to report sales under co-generation and other long-term contracts *(GR2 form)*;
- one to report re-allocations of capital cost *(AC3 form)*; *and*
- one to report custom processing fees paid *(AC5 form).*

Facility Operators submit three forms:

- two to report **allowable costs*** *(capital on AC2 form, operating on AC4 form); and*
- one to claim Sulphur Emission Control Assistance Program (SECAP) annual operating costs *(595 form). (Refer to Section 8.2 on application requirements.)*

The remaining form is the *NGL2,* on which **Designated Storers*** report annual storage costs. Since the **Storage Allowance*** for 1995 onwards is set at $0 per m^3, the NGL2 form will not be required to be filed by royalty clients after 1994.

Group 4 …Monthly submissions

This group consists of five forms that are filed with the Department. They are as follows:

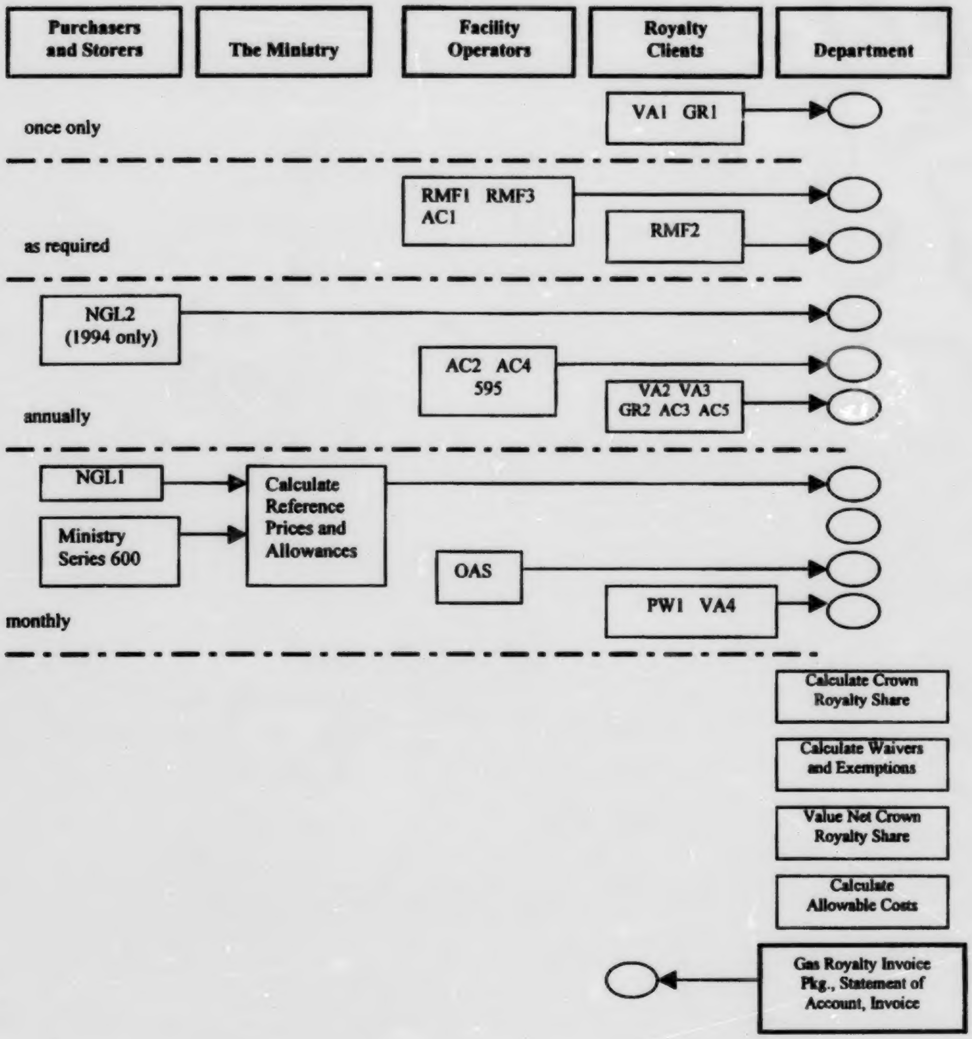
- the gas pricing *(APMC series 600)* forms filed monthly by companies that fall under various categories for which reporting is required under the Natural Gas Marketing Act;
- the **NGL*** pricing/transportation cost *(NGL1 form)* filed monthly by **Designated Purchasers*** of NGLs;
- The Sulphur Corporate Average Price *(VA4 form)* filed monthly by specified royalty clients;
- the **Owner Activity Statement*** *(OAS form)* filed monthly by Facility Operators; *and*
- the Statement of **Proprietary Gas*** - Royalty Waived *(PW1 form)* filed monthly by some royalty clients.

The OAS is a standard format for industry to report gas facility allocation. This standard format facilitates use of electronic data interchange *(EDI*)* technology. It was developed by the Partner Regulatory Information Data Exchange *(PRIDE*)* committee. PRIDE is a collaborative industry and multi-government initiative focused on re-engineering the requirements of industry-to-industry and industry-to-government reporting. The OAS is an industry generated document that provides the pivotal volume/quantity information upon which the simplified Crown natural gas royalty administration depends. It reports working interest owner information for batteries, **gathering systems***, processing plants, injection systems and storage facilities for each production stream where volumes are made available for disposition.

3.3 Crown Royalty Monthly Invoice

The following figure depicts the once-only, as required, annual and monthly reporting required of the petroleum and natural gas industry *(Royalty Clients, Facility Operators, Designated Purchasers, and Designated Storers),* and the flow of information as it relates to the monthly *Gas Royalty Invoice Package.*

****For definition, please see Appendix N - Glossary.***


Purchasers and Storers
The Ministry
Facility Operators
Royalty Clients
Department
once only
VA1 GR1
as required
RMF1 RMF3 AC1
RMF2
annually
NGL2 (1994 only)
AC2 AC4 595
VA2 VA3 GR2 AC3 AC5
monthly
NGL1
Ministry Series 600
Calculate Reference Prices and Allowances
OAS
PW1 VA4
Calculate Crown Royalty Share
Calculate Waivers and Exemptions
Value Net Crown Royalty Share
Calculate Allowable Costs
Gas Royalty Invoice Pkg., Statement of Account, Invoice

4. Alberta's Royalty Share of Gas and Gas Products

4.1 Crown Ownership of Natural Gas

The Crown owns the mineral rights underlying Crown lands. The Crown's right to an owner's share *(the Crown royalty share)* of the minerals produced from lands under lease is established in the Crown lease agreement and in the Mines and Minerals **Act***. The Crown royalty on natural gas or any of the constituent products of natural gas is established in the Natural Gas Royalty Regulation, 1994 *(Alberta Regulation 351/93).*

In the legislation, Crown ownership of natural gas is referenced to the well event and Crown lease agreement from which natural gas is produced.

In practice, the raw gas stream from a well event is processed in a facility together with the raw gas from other well events. The Crown, freehold mineral owner, and other **lessees*** may or may not have common ownership of the raw gas stream(s) processed in a facility. The ownership of the gas and gas products recovered through processing in a facility is determined through allocating the gas and gas products to the raw gas stream(s) *(Well/Well Group/Unit/Injection Scheme)* from which they are produced.

The proportion of allocated gas and gas products under Crown lease *(the Crown interest share)* is the same as the proportion of the raw gas produced from the source well event under lease. However, the Crown interest share of gas and gas products for each working interest owner can be different from the Crown interest share portion of gas and gas products at the well event level.

The *Crown interest share* of gas and gas products is generally determined for the month in which it is produced at the *plant gate* of the facility where the gas and gas products are recovered.

4.2 Crown Royalty Share of Natural Gas

4.2.1 Point of Determination

A.R. 351/93
S.8 (1)(2)(3)(5)

The point at which the Department assesses a Crown royalty share of gas and gas products depends on whether or not the gas has been processed *or reprocessed (refer to Appendix B for description of the **Royalty Triggers***).*

- *If* the gas is **disposed of*** before it is processed at a **gas processing plant***, the Department will assess a Crown royalty share at the last point of measurement before the gas is delivered to the processing plant or disposed of to a pipeline if no processing is required.
- *If* the gas is delivered to an ex-Alberta destination, the Department will assess a Crown royalty share at the last point of measurement before the gas is delivered to the ex-Alberta destination.
- *If* the gas is processed at a gas processing plant *and* the resulting gas and gas products are not reprocessed before they are disposed of, the Department will assess a Crown royalty share at the *plant gate* of the gas processing plant.
- *If* the gas is processed at a gas processing plant *and* the resulting gas or gas products are reprocessed *(at other than a **mainline straddle plant*** or a **field straddle plant***)* before they are disposed of, *then:*
  - for gas, the Department will assess a Crown royalty share at the *plant gate* of the **reprocessing plant***; *and*

For definition, please see Appendix N – Glossary

- for products, the Department will assess a Crown royalty share at the *plant gate* of the first gas processing plant. Residue gas that results from the processing of royalty paid gas products will not be assessed further royalties.
- *If* unprocessed gas is delivered to a field straddle plant for processing (approved by the Minister) before being disposed of, the Department will assess a Crown royalty share of gas and gas products at the plant gate of the field straddle plant.
- *If* unprocessed gas is delivered to a mainline straddle plant for processing before being disposed of, the Department will assess a Crown royalty share of gas and gas products at the last point of measurement before delivering to the mainline straddle plant.
- *If* the gas is processed at a gas processing plant and the resulting gas and gas products are reprocessed at a **straddle plant***, the Department will assess a Crown royalty share at the plant gate of the first gas processing plant.

(Please refer to Section 5.2 for the royalty treatment of raw and residue gas consumed.)

4.2.2 Crown's Royalty Share

The Crown's royalty share of gas and gas products is calculated as:

the quantity of raw gas at the point of disposition *or* the quantity of processed gas, and
gas products at the plant gate
...multiplied by...
the Crown interest percentage
...multiplied by...
the applicable **Crown royalty rate***

Crown royalty rates are described in *Sections 4.9 through 4.13* of this section.

4.3 Responsibility to Account for Natural Gas

S.2(6)

Facility Operators are responsible to account for the quantities of gas and gas products obtained at or disposed from their facilities during a production month, as follows:

- The operator of a *reprocessing facility, other than a mainline straddle plant, or a **fractionation plant***, is responsible for the quantities of gas and gas products obtained from that facility during the production month.
- The operator of a *processing plant* is responsible for the quantities of gas and gas products obtained at that facility during the production month.
- The operator of a *gathering system or a **battery**** is responsible for the quantities of gas and gas products delivered from that facility during the production month, except where:
- the gas and gas products are delivered undisposed to a *processing plant or a reprocessing plant*, or
- the gas and gas products are delivered undisposed to another *gathering system*.
- The operator of a *battery* is responsible for quantities of gas or gas products delivered from that facility during the production month.
- The operator of a **cascade facility*** is responsible for the quantities of gas and gas products allocated to the cascade facility by the downstream Facility Operator.

****For definition, please see Appendix N – Glossary***

4.4 Allocating Gas and Gas Product Ownership

S.21(2)(3) Unless the Minister directs otherwise, Facility Operators are responsible for allocating gas and gas products to owners (royalty clients), as follows:

- An operator of a *reprocessing plant, other than a mainline straddle plant or a fractionation plant:*
  - *may* allocate some or all of the gas and gas products to royalty clients by *Well/Well Group/Unit/Injection Scheme*; *and*
  - *must* cascade any gas and gas products, not allocated to royalty clients, to the operators of gas processing plants, gathering systems or batteries from which they came.
- An operator of a *gas processing plant*:
  - *may* allocate some or all of the gas and gas products to royalty clients by *Well/Well Group/Unit/Injection Scheme*; *and*
  - *must* cascade any gas or gas products, not allocated to royalty clients, to the operators of gathering systems or batteries from which they came.
- An operator of a *gathering system*:
  - *may* allocate some or all of the gas and gas products to royalty clients by *Well/Well Group/Unit/Injection Scheme*; *and*
  - *must* cascade any gas or gas products, not allocated to royalty clients, to the operators of gathering systems or batteries from which they came.
- An operator of a *battery:*
  - *may* allocate some or all of the gas and gas products to royalty clients by *Well/Well Group/Unit/Injection Scheme*; and
  - *must* cascade any gas or gas products, not allocated to royalty clients, to the operator of the battery(ies) from which they came.

(Refer to Appendix A for Volumetric Reconciliation and Appendix B for Royalty Triggers.)

In all instances where a facility has cascaded quantities of gas or gas products from a downstream facility, the operator of the receiving facility is responsible for further allocating those quantities according to the principles established for that type of facility.

S.21(4) Facility Operators are to report gas and gas product allocations to the Department using an Owner Activity Statement (OAS). The Department will only accept the OAS document if it is in electronic data interchange (EDI) format. The Facility Operators must make their own arrangements to have their OAS documents delivered to the Department via EDI.

S.21 (6) The Department must receive OAS documents on or before the 15th of the second month following the production month to which the statement relates.

The Facility Operator should send Owner Activity Statements to the owners and cascade Facility Operators on or before the 25th day of the month following the production month.

Refer to *Section 21.4* for a description of the procedures related to Owner Activity Statements.

4.5 Establishing the Crown Interest Share

Before the Department can calculate the Crown royalty share of minerals produced from lands under Crown leases, it must first establish the share that is produced and recovered from the Crown mineral right *(the Crown interest share)*. As discussed in *Section 4.1*, the Crown interest share is determined by the ownership of the minerals at the well event from which the natural gas is recovered. The accounting for the Crown interest share may be done on the basis of logical groupings of individual well events. For Crown royalty purposes, these groupings are categorized as follows:

- *Well*—a single well event;
- *Well Group:*
  - *Consolidated Single Well Group*—a grouping of two or more single well events;
  - *Non-Consolidated Single Well Group*—**production entity*** type such as PROJ (Project), BLOCK (Oil Block), NUSPC (Non-Unit Spacing), NUGAS (Non-Unit Gas), NBLOCK (Non-Block), and NUOIL (Non-Unit Oil);
- *Unit*—well events subject to a unit agreement; *or*
- *Injection Scheme.*

All the well events in the *Consolidated Single Well Group* must have:

- common mineral ownership (the ownership of the mineral rights must be Crown, freehold, Aboriginal or other federal jurisdiction in the same proportion for all the wells in the group);
- common old/new **vintage*** (the Crown vintage of all well events in the group must be the same); *and*
- common ownership for the purpose of discharging Crown royalty (the responsibilities to pay Crown royalty for each well event in the group must be identical for all royalty clients).

An *Injection Scheme* must:

- be an approved Injection Scheme for the purpose of Crown royalty;
- encompass all of the well events through which gas and gas products are injected into the approved Injection Scheme;
- encompass all well events through which injected gas and gas products may be subsequently reproduced from the approved Injection Scheme (mandatory for Enhanced Oil Recovery and **Commercial Storage Schemes***);
- have the same vintage for all the wells; *and*
- have the same Crown interest for all the wells (except commercial storage schemes).

For definition, please see Appendix N - Glossary

4.6 Responsibility to Register Well/Well Group/Unit/Injection Scheme and Facilities

4.6.1 Well/Well Group/Unit/Injection Scheme

S.19(1) Unless the Minister directs otherwise, Facility Operators are to apply to the Department to establish *Well/Well Group/Unit/Injection Scheme* for the purpose of Crown royalty reporting and determination. The requirement to register *Well/Well Group/Unit/Injection Scheme* is as follows:

- a *Well*
    - must be registered if the Crown interest share is greater than 0% but less than 100%, and if all the working interest owners' Crown interest share is not the same as the well's Crown interest *or*
    - need not be registered if the Crown interest is either 0% or 100% (see *Section 21.3)*;
- a *Consolidated Single Well Group* must be registered *(see Section 21.1)*;
- a *Non-Consolidated Single Well Group* must be registered if the Crown interest share is greater than 0% but less than 100%, and if all the working interest owners' Crown interest is not the same as the well's Crown interest (see *Section 21.3)*;
- The Department executes a Unit and the Exhibit A of the Unit-Agreement is registered for calculating Crown royalty.
- an *Injection Scheme* must be registered *(see Section 21.3)*.

NOTE: TO ENSURE THAT THE CORRECT CROWN INTEREST IS USED TO CALCULATE ROYALTY, THE SINGLE WELL, INJECTION SCHEME AND UNIT AGREEMENT EXHIBIT A REGISTRY INFORMATION MUST BE UPDATED AFTER WORKING INTEREST OWNERSHIP CHANGES. EXHIBIT A TO THE UNIT AGREEMENT BECOMES THE SOURCE DOCUMENT FOR OWNERSHIP INFORMATION. SINCE ALL CHANGES CONTAINED IN THE REVISED EXHIBIT A BECOMES EFFECTIVE FROM THE LATEST REVISION DATE OF EXHIBIT A, IT IS NOT PRACTICAL TO PREPARE REVISIONS CONTAINING SEVERAL CHANGES WITH DIFFERENT EFFECTIVE DATES WITHIN EACH EXHIBIT A. IF THIS OCCURS THEN THE LATEST REVISION DATE WILL BE USED AS THE EFFECTIVE DATE FOR ALL CHANGES. THEREFORE, ALL CHANGES MUST PROMPTLY BE REGISTERED WITH THE DEPARTMENT TO ENSURE THAT CORRECT EFFECTIVE DATES ARE USED. THE DEPARTMENT WILL ONLY ACCEPT CHANGES BY SUBMITTING A REVISED EXHIBIT A AND WILL NOT ACCEPT CHANGES IN ANY OTHER MANNER (I.E. BY PHONE OR LETTER). IF THE REGISTRIES ARE NOT UPDATED, THEN FOR THE PURPOSE OF CROWN ROYALTY CALCULATION, THE CROWN INTEREST WILL DEFAULT TO 100% AND FOR THE PURPOSE OF INJECTION CREDIT CALCULATION, THE CROWN INTEREST WILL DEFAULT TO 0%, TO ESTABLISH THE CROWN'S SHARE OF THE VOLUMES OF THE ROYALTY CLIENT WHOSE CROWN INTEREST IS NOT INDICATED IN SUCH REGISTRIES.

4.6.2 Facility Operator Changes

To enable the Department to notify and assess the correct Facility Operator for volumetric discrepancies and penalties, Facility Operators must notify the Department immediately of any EUB Facility Operator changes to Gas Plants (GP) and Gas Gathering Systems (GS). This should be done by forwarding a completed "Facility Operator Change Form - OC1" to the Gas Royalty Client Services Help Desk. This form is provided in Appendix P.

Every month, a list of Operator Changes is sent to the EUB and also published in the Mineral Operations Information Bulletin.

NOTE:

·THE DEPARTMENT DOES NOT REQUIRE NOTIFICATION OF BATTERY AND INJECTION FACILITY OPERATOR CHANGES SINCE THIS INFORMATION IS CAPTURED FROM *S1* AND *S18* DOCUMENTS.

·THE CHANGE IN EUB FACILITY OPERATOR MUST ALSO BE COMMUNICATED TO THE OTHER UPSTREAM AND DOWNSTREAM EUB FACILITY OPERATORS.

4.6.3 Out of Province Facilities

All new and/or changes to the wells, units and facilities located out of the province that will be reported on the OAS in the future, must be communicated in writing to Gas Royalty Client Services Help Desk to avoid OAS rejection and potential **Provisional Royalty Assessment ***.

4.7 Transactions Which Trigger Crown Royalty

The Owner Activity Statement (OAS) is the only form used by industry to report gas and gas product allocations to the Department. OAS is designed to fulfil the requirements of industry-to-industry reporting and industry-to-government reporting. The OAS procedures and reporting transactions that will trigger the calculation of Crown royalty share and the reporting rules for Injection Schemes are described in *Sections 21.4, 21.5 and 21.6.*

4.8 Responsibility for the Crown Royalty Share

The responsibility for discharging the liability for Crown royalty is based on the allocation of quantities of gas and gas products to royalty clients at each *Well/Well Group/Unit/Injection Scheme*, as reported to the Department each production month on the OAS forms. The Department holds the royalty client, to whom the quantities of gas and gas products are allocated, responsible for discharging the Crown royalty share.

S.20(2) *If* a royalty client (assignor) wishes to reassign the volumes (both Crown and freehold volumes) to one or more persons (assignees) at a *Well/Well Group/Unit/Injection Scheme, and*:

- wishes to have the person(s) accept responsibility for their (i.e. the assignee(s)) portion of the volumes, *then,*
- the royalty client who receives the allocation on OAS forms must apply to the Department to reassign all or part of the volumes to one or more royalty clients through an RMF2 form.
- once the royalty responsibility for a client has been established on the RMF2 form, that client may not further reassign all or a portion of their royalty responsibility to a different client.

If a royalty client wishes to assume responsibility for his volumes that are allocated to another royalty client on an OAS document, then the latter must apply for reassignment of that obligation.

The royalty client requesting to reassign the volume must provide the Department with written concurrence from each royalty client to whom an obligation is to be assigned.

The reassignment of volumes is effective from the production month specified in the application, up to the effective date of a subsequent application to terminate that agreement. Only an assignor can terminate an RMF2 assignment. Concurrence is not required from the assignees in this case.

In all cases, the RMF2 forms must be submitted to the Department by the assignor and not the assignee. The RMF2 forms must be used only to assign volumes that belong to the assignee(s) If the RMF2 form is to be processed retroactively, then the assignor must ask the Department in writing for this retroactive processing because penalties will be charged on retroactive processing.

For definition, please see Appendix N - Glossary

NOTE:

(1) REASSIGNED VOLUMES WILL BE REPORTED ON THE ASSIGNEE'S INVOICE* WITH ROYALTY CALCULATION BASED ON THE ASSIGNEE'S CROWN INTEREST AND ELECTED GAS VALUATION METHOD. THE REASSIGNED VOLUMES WILL BE INCLUDED IN THE ASSIGNEE'S ANNUAL CORPORATE EFFECTIVE ROYALTY RATE* CALCULATION.

(2) IF THE ASSIGNEE'S CROWN INTEREST IS NOT AVAILABLE TO THE CROWN, THE ASSIGNOR'S CROWN INTEREST WILL BE USED TO CALCULATE ASSIGNEE'S ROYALTY LIABILITY.

(3) IF THE ASSIGNOR'S CROWN INTEREST IS NOT AVAILABLE TO THE CROWN, THE WELL/WELL GROUP/UNIT/INJECTION SCHEMES OVERALL CROWN INTEREST WILL DEFAULT TO 100% TO CALCULATE ROYALTIES. FOR INJECTION CREDIT*, THE CROWN INTEREST WILL DEFAULT TO 0%.

(4) VOLUME REASSIGNMENT MUST NOT BE DONE AT A SINGLE WELL LEVEL (UNLESS IT IS A ROYALTY HOLIDAY WELL) IF THE WELL IS TIED TO A WELL GROUP, UNIT OR INJECTION SCHEME. THE VOLUME REASSIGNMENT MUST BE DONE AT THE HIGHEST LEVEL IE. WELL GROUP, UNIT, OR INJECTION SCHEME.

The procedures for Reassignment of volumes are described in *Section 21.2.*

4.9 Crown Royalty Rate for Raw Gas, Residue Gas and Ethane

4.9.1 Calculation Criteria

No distinction is made between raw gas, residue gas and ethane for calculating the Crown royalty share. The Crown royalty share is a percentage (the Crown royalty rate) of the Crown interest share of production.

The Crown royalty rates for gas (raw gas, residue gas and ethane) are calculated each month according to the prescribed formulae that provide price sensitivity ***(Gas Par Price*)*** and distinguish between ***old gas**** and ***new gas**** *(Vintage and Select Prices*)*. The Crown royalty rate is applied to raw gas and residue gas on 10^3m^3 and gigajoule (GJ) volumes. Ethane, which is measured in m^3, is converted to a gas equivalent heat content and the Crown royalty rate is then applied to m^3 and GJ volumes. There are separate Crown royalty rates for gas that is of *"old"* or *"new"* vintage. *(For information on how to calculate the Crown royalty rate, please refer to Section 25.5).*

4.9.2 Gas Par Price and Select Prices

The Gas Par Price for a production month is the Gas Reference Price for the preceding production month. An **Old Gas Select Price*** and a **New Gas Select Price*** is determined by the Minister for each year. The Select Prices apply to all production months in that year. *(For further information on Select Prices, please refer to the Information Letter 96-9).*

The Department will publish the Gas Par Price, the Old Gas Select Price and the New Gas Select Price in an *Information Letter* on the 15th day of the second month following the production month to which they will apply. If this day falls on a weekend or a holiday, the next business day will apply.

The Gas Par Price, Old Gas Select Price and New Gas Select Price that are established for a production month will not be changed retroactively.

Calculation of the Gas Par Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

For definition, please see Appendix N - Glossary

4.9.3 Gas Vintage

Sch. 5 The *vintage* of gas is determined by the date of discovery, or first production from the **pool**[*]. Generally speaking:

- *new gas* is gas obtained from a pool
  - discovered on or after January 1, 1974, *or*
  - discovered before January 1, 1974, *if* no gas or other gas products from that pool had been sold or consumed for some useful purpose before January 1, 1974;
- *old gas* is gas that does not qualify as new gas.

The Minister may determine that gas obtained from a well event or unit is only partly new gas and may assign a vintage between 0% new and 100% new if:

- production from a single well event is obtained from more than one pool; *and*
- one or more of the pools were known to exist before January 1, 1974

4.9.4 Old Gas Royalty Rate

Sch.1 - S.(1)(2) The Crown royalty rate for old gas in a month, expressed as a percentage of the Crown interest share, is calculated as:

$$R\% = \frac{15(SP) + 40(GPP - SP)}{GPP}$$

WHERE:
R% = THE CROWN ROYALTY RATE FOR OLD GAS.
SP = THE OLD GAS SELECT PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
GPP = THE GAS PAR PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.

The minimum Crown royalty rate for Old Gas is 15%.

The maximum Crown royalty rate for Old Gas is 35%.

4.9.5 New Gas Royalty Rate

Sch.1-S.(1)(2) The Crown royalty rate for new gas in a month, expressed as a percentage of the Crown interest share, is calculated as:

$$R\% = \frac{15(SP) + 40(GPP - SP)}{GPP}$$

WHERE:
R% = THE CROWN ROYALTY RATE FOR NEW GAS.
SP = THE NEW GAS SELECT PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
GPP = THE GAS PAR PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.

The *minimum Crown royalty rate for New Gas is 15%.*

The maximum Crown royalty rate for New Gas is 30%

For definition, please see Appendix N – Glossary

4.9.6 Low Productivity Well Allowance*

Sch.1 - S.(3) The Crown royalty rates for both old and new gas will be reduced for well events that:

- are classified by the EUB as a **gas well*** event, or an oil well event (beginning January 1995); *and*
- have a monthly average daily gas production rate of less than 16.9 10^3m^3 per day for gas well events; *or*
- have a monthly average daily production rate under 0.15 m^3 per day of oil and 16.9 10^3m^3 of gas for an oil well event.

Average Daily Production* (ADP) for gas is calculated as:

volume of natural gas obtained in the month from the gas event *(in 10^3m^3)*
...divided by...
number of hours of operation of the well in the month
...multiplied by...
24

Average Daily Production (ADP) for oil is calculated as:

volume of oil obtained in the month from the oil event *(in m^3)*
...divided by...
number of hours of operation of the well in the month
...multiplied by...
24

The Crown royalty rate for a well event that qualifies for low productivity (for either old or new gas) is calculated as:

$$R\% = RC - \left[\frac{(RC - 5\%) \times (16.9 - ADP)^2}{16.9^2} \right]$$

WHERE:
R% = THE CROWN ROYALTY LOW PRODUCTIVITY RATE.
RC = THE CROWN ROYALTY RATE THAT WOULD APPLY IF THE ROYALTY IS CALCULATED AT EITHER THE OLD OR NEW GAS ROYALTY RATE *(WHICHEVER IS APPLICABLE)* FOR THE PRODUCTION MONTH.
ADP = THE AVERAGE DAILY PRODUCTION OF GAS FOR THE WELL EVENT FOR THE PRODUCTION MONTH (in 10^3m^3).

Please refer to *Section 25.6.1* for an example of low productivity calculation.

4.10 Crown Royalty Rate for Propane and Butane

Sch.4 - S.(1) The Crown royalty rate for propane and butane, expressed as a percentage of the Crown interest share, is 30%.

For definition, please see Appendix N - Glossary

4.11 Crown Royalty Rate for Pentanes-Plus

Sch.2 - S.(1) The Crown royalty rates for Pentanes-plus are calculated each month according to prescribed formulae that provide price sensitivity ***(Pentanes Par Price* and Select Price*)*** and distinguish between *old* and ***new Pentanes-plus**** *(Vintage and Royalty Factor)*. There are separate Crown royalty rates for old and new Pentanes-plus.

4.11.1 Pentanes Par Price, Select Price and Royalty Factors

The Minister determines a Pentanes Par Price for each production month, which is the Pentanes Reference Price for the preceding production month, minus an allowance for transportation. The deduction for transportation is calculated as the volume-weighted average of the four regional **Transportation Allowances*** for specification pentanes-plus in the previous production month *(refer to Section 15.3.1)*.

The Minister determines:

- a **Pentanes Select Price*** for each year, and this Select Price for a year applies to all production months of that year.
- an **Old Pentanes-plus*** Royalty Factor and a New Pentanes-plus Royalty Factor for each year. These royalty factors will apply to all production months of that year.

The Department will publish the Pentanes Par Price and Pentanes Select Price in an Information Letter on or before the 15th day of the second month following the production month to which they will apply. If this date falls on a weekend or holiday, the next business day will apply.

The Pentanes Par Price, Pentanes Select Price, Old Pentanes-plus Royalty Factor and New Pentanes-plus Royalty Factor that are established for a production month will not be changed retroactively.

Calculation of the Pentanes Par Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

4.11.2 Pentanes-Plus Vintage

Sch.5 - S.(2) Unless the Minister determines otherwise, effective January 1, 1994, the vintage of Pentanes-plus is the same as the gas with which it is produced and from which it is recovered.

For definition, please see Appendix N - Glossary

4.11.3 Old Pentanes-Plus Royalty Rate

Sch.2 - S.(1) The Crown royalty rate for old Pentanes-plus in a month, expressed as a percentage of the Crown interest share, is calculated as:

$$R\% = \frac{22(SP) + RF(PP - SP)}{PP}$$

WHERE:

R% = THE CROWN ROYALTY RATE FOR OLD PENTANES-PLUS.
SP = THE PENTANES SELECT PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
RF = THE OLD PENTANES-PLUS ROYALTY FACTOR (CURRENTLY SET AT 50) PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
PP = THE PENTANES PAR PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH TO WHICH THE CROWN ROYALTY RATE APPLIES.

The minimum Crown royalty rate for Old Pentanes-plus is 22%.

The maximum Crown royalty rate for Old Pentanes-plus is 50%.

4.11.4 New Pentanes-Plus Royalty Rate

Sch.2 - S.(1) The Crown royalty rate for new Pentanes-plus in a month, expressed as a percentage of the Crown interest share, is calculated as:

$$R\% = \frac{22(SP) + RF(PP - SP)}{PP}$$

WHERE:

R% = THE CROWN ROYALTY RATE FOR NEW PENTANES-PLUS.
SP = THE PENTANES SELECT PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
RF = THE NEW PENTANES-PLUS ROYALTY FACTOR (CURRENTLY SET AT 35) PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH.
PP = THE PENTANES PAR PRICE PRESCRIBED BY THE MINISTER FOR THE PRODUCTION MONTH TO WHICH THE CROWN ROYALTY RATE APPLIES.

The minimum Crown royalty rate for New Pentanes-plus is 22%.

The maximum Crown royalty rate for New Pentanes-plus is 35%.

4.12 Crown Royalty Rate for Sulphur

Sch.3 - S.(2) The Crown royalty rate for sulphur, expressed as a percentage of the Crown interest share, is $16^{2}/_{3}$% *(16.66667).*

4.13 Crown Royalty Rate for Other Products

Sch.4 - S.(1) The Crown royalty rate for other products, expressed as a percentage of the Crown interest share, is 30%. These products are:

- carbon dioxide;
- nitrogen;
- helium; and
- **light ends***

**(For definition, please see Appendix N – Glossary)*

5. Exemptions, Waivers and Other Royalty Reductions

5.1 Crown Royalty Holidays

A.R. 351/93 Sch. 6

Periodically, the Crown introduces programs to assist the petroleum and natural gas industry, and to encourage development of petroleum and natural gas reserves in Alberta. Program benefits are through reductions in the amount of royalty that would otherwise be payable on the Crown interest share of the production from eligible well events.

Single well reporting is required for production from holiday wells. The Department calculates the monthly exemption based on OAS production and allocation reporting provided for determining Crown royalty.

5.1.1 Deep Gas Royalty Holiday

The **Deep Gas Royalty Holiday Program (DGRHP)*** applies to any well spudded or deepened on or after June 1, 1985:

- into a producing zone, the top of which is deeper than 2,500 m; *and*
- within a drilling spacing unit that is wholly outside a deep gas pool designated by the EUB at June 1, 1985.
- Program benefits must be taken within 10 years of the finished drilling date of the well.

** Please refer Section 20.2 for additional information.*

5.1.2 Continuing Benefits Under Past Drilling Incentive Programs

Production from applicable wells continue to benefit from Crown royalty exemptions established under past drilling incentive programs. These programs are now closed. The four programs funded through Crown natural gas royalty that remain active at January 1, 1994, are:

Exploratory Gas Well Incentive Program

- wells spudded August 1985 through May 1988; ***eligibility is closed;***
- exemption ends after 12 months of production (not necessarily consecutive) have been taken or the benefit obtained equals a specified calculated limit, whichever occurs later,
- regardless of which of the two limitations applies, the value of the Crown royalty holiday cannot exceed $2 million,
- program benefits must be taken before May 31, 1998.

A.R. 137/84

Exploratory Drilling Incentive Program 1984

- wells spudded April 1984 through July 1985; ***eligibility is closed;***
- exemption ends after 12 months of production (not necessarily consecutive) have been taken,
- the value of the Crown royalty holiday cannot exceed $2 million, *and*
- program benefits must be taken within 12 years of the finished drilling date of the well event.

A.R. 210/83

Exploratory Drilling Incentive Program

- wells spudded May 1983 through March 1984; ***eligibility is closed;***
- exemption ends after 12 or 24 months of production (not necessarily consecutive) have been taken,
- program benefits must be taken within 12 years of the finished drilling date of the eligible well event.

A.R. 212/81

Exploratory Drilling Incentive Program

- wells spudded April 1981 through April 1983; ***eligibility is closed***;
- exemption ends after 12, 24 or 36 months of production (not necessarily consecutive) have been taken,
- program benefits must be taken within 12 years of the finished drilling date of the eligible well event.

****For definition, please see Appendix N - Glossary***

5.1.3 Otherwise Flared Solution Gas Royalty Waiver Program (OFSG)

AR 351/93
Section 12.1.1

As announced in Information Letter 99-19 a royalty waiver program will be implemented by the Department of Resource Development to encourage the reduction of solution gas flaring in the Province. For those clients who have been approved for this program either through the pre-qualification process or through the application process, conserved solution gas and gas by-products that would have normally attracted a Crown Royalty charge will have that royalty obligation waived. The royalty waiver will last for a maximum period of ten (10) years from the first production period in which the OFSG status was granted.

The program is effective January 1, 1999 production period. Business processes and enabling legislation was implemented in the fall of 1999. Applications under the program can be made to determine eligibility.

For those royalty clients in which the end-use of the solution gas and by-products will result in required S and OAS reporting and thus will be subject to Crown Royalty charges and offsetting OFSG credits, please note the following procedure as it relates to the Otherwise Flared Solution Gas Program (OFSG):

Pre-Qualification of Eligible OFSG Wells

To reduce the administrative burden for determination of eligible program status, wells with an established history of flaring up to November 30, 1998 were automatically approved for the OFSG program. The determination of well pre-qualification status is as follows:

- Those well events associated with crude oil batteries that have not reported deliveries of solution gas since May 1989 including deliveries to injection schemes. Note: Bitumen batteries are excluded from this royalty waiver program.
- Those well events associated with crude oil batteries flaring solution gas at the end of the November 1998 production month.
- Crude Oil batteries that first produced oil prior to March 1, 1998. Those batteries in which oil production first started between March 1, 1998 to November 30, 1998 do not reflect an adequate history of flaring and thus are excluded from pre-qualification.
- Wells with an active status. This excludes wells with a current shut-in, abandoned, suspended, etc. status. Applications are required for these wells to be considered by the Department for OFSG approval status.

A complete listing of pre-qualified wells is provided on the Department's website at www.resdev.gov.ab.ca/gas/royalty/index.htm.

Application-based Qualification of Eligible OFSG Wells

Those battery/well combinations excluded from the pre-qualified process above must submit an *OFSG Form* to the Department. The application form as well as the supporting documentation required with the application form follows the procedures as outlined in Section 2.4 of the *EUB Upstream Petroleum Industry Flaring Guide G-60.*

The application form is to be submitted by the battery operator, on behalf of all working interest owners.

Upon receipt of the application form, the Department will forward the form to the EUB for assessment of the economic information. The EUB will assess applications on an "economic limit" basis, in which battery operators will have to demonstrate at what volume conservation rate the project reaches the uneconomic-economic threshold. Please refer to the section entitled *Apportionment Factor* below.

Results of the application should be made available to the royalty client within forty (40) days of when the form was received by the Department. Approved wells will have the status granted effective the first day of the production month in which the form was received. For example, an application received by the Department on September 28, 1999 (and subsequently approved) will have the effective date set at 1999/09/01. Royalty clients not approved for the program will be advised in writing of the reason(s) for application denial.

Time Period for Applications (Applicable up to January 1, 2000)

Subject to the exception referred to below, applications under the Otherwise Flared Solution Gas Royalty Waiver Program will not be accepted more than six months after the date when, according to the records of the Energy and Utilities Board, routine flaring or venting of all or part of the solution gas recovered from a well event permanently ceased.

An exception will be made however, for applications received before January 1, 2000 relating to well events where, according to the records of the Board, routine flaring or venting of all or part of the solution gas recovered from the well event permanently ceased between December 1, 1998 and June 30, 1999 (inclusive).

Apportionment Factor (A-Factor)

In some cases the EUB will determine that a portion of the solution gas conserved at a battery level is economic. Therefore, the production wells tied to the battery should not receive a 100% royalty waiver. A point is reached on an economic limit basis in which incremental volumes of solution gas are uneconomic to conserve and thus these incremental volumes should be subject to a royalty waiver. This apportionment factor will be used to determine the amount of royalty waiver applicable to each well. For example, a 0.200 apportionment factor implies a 20% royalty waiver on all gas and gas-products, 0.350 implies a 35% royalty waiver, etc. The apportionment factor is determined at a battery level and will be used for all approved wells tied to that battery.

Should wells be subject to an A-Factor, the Department will communicate the factor to the respective battery operator. All pre-qualified wells will have the A-Factor set to 1.000.

OAS Reporting

In order to obtain the royalty waiver, royalty clients must report the applicable volumes at the **single well level**. Thus, if a well is tied to a project, unit or well group the OFSG volumes must be reported at the unique well identifier level. Reporting at the higher level (unit, well group, etc) will result in no royalty waiver, and reporting at the single well level for a period of time in which the well does not have OFSG status will result in an OAS line rejection and Provisional Assessment, where applicable.

Invoice Changes

Those royalty clients participating in the OFSG waiver program that receive the invoice via paper will see a line item appearing on the Invoice cover page. The text "Otherwise Flared Solution Gas" will appear under the *Credits* portion of your invoice, with a one-line credit amount summed to a royalty payer level. The supporting *Production Year Detail* and *Billing Period Detail* reports will display the OFSG credits under the existing SECAP field. If a royalty client is involved in both SECAP and OFSG waiver programs, a bracketed 'S' or 'F' will appear after each credit item, to differentiate the respective credit amounts.

Those royalty clients receiving the invoice via the User Defined Format (UDF) will see a charge category of 250 (Otherwise Flared Solution Gas) appearing on the invoice.

To ensure timely implementation of this program, and to minimize the impacts for all royalty clients, the *Crown Royalty Details* (CRD) portion of the monthly invoice was not altered. Thus, those clients involved in the OFSG program will observe the individual well identifiers as being charged crown royalty within the CRD (all variables, calculations displayed as expected), with the offsetting credit amounts posted at the invoice level.

Allowable Cost Reporting

Royalty clients incurring additional capital expenditures to enhance the conservation rate of solution gas may claim these costs in accordance with the existing Natural Gas Royalty Regulation. Please refer to Section 7 and Section 16.

The calculation methodology of the royalty client's Corporate Effective Royalty Rate (Section 16.8.2) will not be changed. Those OFSG volumes subject to a portion of Crown royalty will be included in the numerator calculation, while all OFSG volumes will be included in the denominator. Royalty clients receiving a 100% waiver will have no volumes used in the numerator calculation and all volumes included in the denominator.

Application Detail

Please include in the application:

- An economic evaluation using the parameters outlined in Section 2.4 of the EUB Upstream Petroleum Industry Flaring Guide, G-60.
- The economic evaluation must include the optimal solution gas conservation case, which is defined as the conservation rate with the maximum Net Present Value (NPV).
- If the NPV of the optimal case is negative, 100% of the solution gas and by-products will qualify for the royalty waiver.
- If the optimal NPV is positive, the evaluation must also include the economic limit case. The economic limit case is the conservation rate that provides a NPV of zero (the incremental economics of additional conservation above the optimal rate will be negative, resulting in a positive but declining NPV until the economic limit volume is reached). Only the fraction of gas production above the economic limit volume will qualify for the royalty waiver.

The following information is required within the application:

1. An area map and description of the existing facilities and facilities required to conserve the solution gas.

2. A discussion of the methods of gas conservation that were investigated. This would include any alternative technologies or designs investigated, the operator conserving gas independently and jointly with other operators in the area, and other alternative methods that are feasible such as the generation of electricity.

3. Detailed information to support the calculation of remaining reserves and data used to establish the production forecast.

4. A list of wells that are, or will be producing to the battery (please complete Page 2 of the application form). Only those wells associated with the conservation project are to be included.

5. A detailed breakdown of capital costs showing equipment costs, material costs, installation costs and Engineering costs. The costs will be AFE (Approved for Expenditure) quality numbers.

6. A detailed printout from an economic evaluation program that includes the before tax NPV (at the discount rate outlined in the EUB Upstream Petroleum Industry Flaring Guide, G-60, section 2.4.2, point no. 9) for each case evaluated:

   a) **For a solution gas conservation project**:
      - i) A forecast of raw solution gas production, shrinkage (fuel, flaring and product shrinkage) sales gas (volumes and GJ's) and natural gas liquid (NGL) volumes recovered by year.
      - ii) A before tax cash flow summary schedule by year that shows: capital investment, gas and NGL sales, prices and revenue, royalty payable, freehold tax if applicable, operating expenses, and cash flow. The Alberta Royalty Tax Credit and income taxes are not to be included. Note from Section 2.4 of the EUB Upstream Petroleum Industry Flaring Guide, G-60, that operating expense is deemed to be 10% of the installed cost of the conservation facilities.
      - iii) A complete schedule of all royalty payable (without deducting the OFSG royalty waiver) that sets out Crown interest, gross royalty, low productivity allowance and the Crown share of allowable costs.

   b) **For a solution gas conservation project with power generation:**

      - i) A forecast of raw solution gas production, shrinkage (flaring and product shrinkage) inlet fuel gas volumes for power generation (volumes and GJ's) and natural gas liquid volumes recovered by year.
      - ii) A before tax cash flow summary schedule by year that shows: capital investment, kwh generated, sales price or displacement cost per kwh, revenue, royalty payable, operating expenses and cash flow. The Alberta Royalty Tax Credit and income taxes are not to be included. Note from Section 2.4 of the EUB Upstream Petroleum Industry Flaring Guide, G-60, that operating expense is deemed to be 10% of the installed cost of the conservation facilities.
      - iii) A complete schedule of royalty payable (without deducting the OFSG royalty waiver) that sets out Crown interest, gross royalty and low productivity allowance.
      - iv) A summary of the power purchase agreement when the power is used on site [displacement] or the sales contract when the power is sold.

Economic Parameters to be used in Economic Assessments for Otherwise Flared Solution Gas Royalty Waiver Applications.

Taken from Section 2.4.2 of the EUB Upstream Petroleum Industry Flaring Guide, G-60.

The following assumptions and parameters will be used in the decision tree analysis:

1. The evaluation will be a before tax analysis.
2. The commodity price forecasts used in evaluations of conventional gas conservation projects (gas gathered, processed and sold to gas markets) will be the most recently published by Dobson Resource Management. In Dobsons' survey, the average nominal large firms consultants Alberta plant gate TCGSL " blended " price (Cdn.$/GJ) for natural gas will be used in evaluations. TCGSL is the TransCanada Gas Services blended price at plant gate. The forecast used for natural gas liquids will be the large firms average nominal consultants price FOB Edmonton in Cdn.$/m^3. The forecasts are available in Dobsons' publication "Survey of Hydrocarbon Price Forecasts utilized by Canadian Petroleum Consultants and Canadian Banks" which is updated semi-annually and available for a nominal cost per publication. The publication will also be available at the EUB library.
3. The power price forecast for electrical power projects will be the time weighted average of the previous twelve months paid by the Alberta Power Pool for power generated or the cost of the power displaced at a site. The power price will be escalated at the annual rate of inflation.
4. The operator will provide information to support the calculation of remaining reserves and to establish the production forecast. This would include planned drilling programs and the implementation of pressure maintenance schemes.
5. A detailed breakdown of capital costs showing equipment costs, material costs, installation costs and engineering costs. Capital costs will be AFE (approved for expenditure) quality numbers. Capital costs incurred prior to the initiation of the solution gas project (sunk costs) will not be included in the analysis. Only future capital costs related to solution gas conservation will be included.
6. The incremental annual operating costs for the solution gas project will be equal to 10% of the capital cost to initially install the facilities. The 10% allowance covers incremental expenses to operate equipment, gas transportation fees, and gas processing fees.
7. The incremental annual operating costs for power generation projects will be equal to 10% of the capital cost to initially install the generation facilities. Standby fees would be in addition to the 10% allowance.
8. The long term inflation rate will be based on the Consumer Price Index forecast, which is available from the same table in the Dobsons' Survey used for natural gas prices. A constant rate of 2.5% will be used for 1999.
9. The discount rate will be equal to the prime lending rate of the Alberta Treasury Branch on loans payable in Canadian dollars plus three percent based on the month preceding the month the evaluation is conducted. The discount rate will be reviewed periodically and will be revised if the cost of capital for the oil and gas industry changes significantly.
10. Only revenue, minus net royalties, from incremental gas and gas by-products that would otherwise be flared will be included in the economic evaluation.
11. A project will be considered economic if the incremental economics of solution gas conservation generates a net present value (NPV) greater than zero.
12. When evaluating existing flares, the economic evaluation must account for any cost savings such as reduced trucking, equipment rental and operator costs resulting from the conservation project.

5.2 Raw Gas and Residue Gas Consumed

5.2.1 Gas Consumed in Gas Compressing, Gathering and Processing

S.12(1)(a) Crown royalty is not payable on flared gas, or on raw gas or residue gas consumed as fuel in the compressing, gathering or processing of natural gas derived from the same source pool as the consumed or **flared*** gas. No application is required. This does not apply to **fuel gas*** produced or consumed at field straddle plants.

5.2.2 Gas Consumed in Drilling and Production

S.12(1) An application is not required for royalty exemption, unless the Minister specifies otherwise, on raw gas or residue gas consumed to drill or otherwise produce from Crown mineral lease that is not an oil sands lease or an **experimental oil project***.

5.2.3 Gas Consumed in Oil Sands Schemes and Experimental Oil Projects

S. 12(1)(b)(c) The Minister may waive Crown royalty share on raw gas or residue gas consumed as fuel in **commercial oil sands schemes*** or certain experimental oil projects (refer to Information Letter 92-25 and *Section 20.3* for further details and definitions).

For definition, please see Appendix N – Glossary

5.3 Injected Gas and Gas Products

5.3.1 Injected Schemes Eligible for Crown Royalty Credit

Where a royalty client injects gas or a gas product into a scheme ordered or approved by the EUB under Section 26 of the *Oil and Gas Conservation Act*, the Crown will contribute its royalty share of that gas or gas product. The injected gas or gas products will be considered native (for Crown royalty purposes only) to the reservoir into which they are injected, and will be subject to Crown royalty when reproduced.

S.16(1)(2)(3) The Department will calculate an injection credit for the amount determined as the Crown's royalty share of the royalty client's injected gas or gas product. It will then apply that injection credit to the royalty client's corporate account for the production month in which the injection occurs. *(Please refer to Section 20.4).*

5.3.2 Commercial Storage Schemes

Commercial storage generally refers to storage that is not primarily related to optimization of recovery from the receiving reservoir. Optimization would generally include:

- enhanced hydrocarbon recovery through miscible floods;
- **pressure maintenance***; *and*
- **cycling*** to maximize liquid extraction.

Any storage for a fee or primarily for a market-related purpose will be considered commercial storage.

The Department will maintain records of the volume and **heat content*** of gas injected and withdrawn from Department-approved commercial storage schemes (gas banks). Separate gas bank records will be maintained for each scheme.

The gas recovered from such a commercial storage scheme is not subject to Crown royalty since any royalty liability will have been paid at the time of original production. However, gas or gas products produced from the storage scheme and deemed to be native, are subject to Crown royalty.

Gas or gas products are considered to be produced from the storage scheme and deemed to be native if:

- gas is produced after the scheme's volume in the Department's record of the gas bank for that scheme is zero; *or*
- gas products (propane, butane, pentanes-plus or sulphur) are produced and recovered from a scheme

Please refer to Section 18.4 for additional information.

5.3.3 Responsibility to Account for Injected Gas and Gas Products

S.21(5) Operators of injection facilities (Facility Operators) are to account for the quantities of gas and gas products injected into the Injection Schemes and commercial storage schemes that they operate.

Facility Operators are to allocate gas and gas product injections to royalty clients, by Injection Scheme, for each Injection Scheme they are responsible for.

S.21(6) Facility Operators are to report gas and gas product allocations to the Department using an OAS. The Department must receive OAS documents on or before the 15th day of the second month following production to which the statement relates. If the due date is a weekend or holiday, the next business day will apply.

For definition, please see Appendix N – Glossary

6. Valuation

6.1 Valuing Crown Share of Raw Gas, Residue Gas and Ethane

The valuation of Crown share of raw gas, residue gas and, if value is received, ethane is on a per GJ basis. Ethane, which is in m^3, is converted to GJs by using a factor of 0.28132, and then multiplying the result by a factor of 66.065. (*Source: GPA Publication 2145 S1-90.)* Ethane, as part of NGL mix for which no value is received, will be reported as light ends.

6.1.1 Royalty Client's Election of Valuation Method

A.R. 351/93 Sch.1 - S.5(1) Subject to certain eligibility criteria, royalty clients may choose one of two methods to value their Crown royalty share of raw gas, residue gas and ethane:

- Gas Reference Price; *or*
- Gas Corporate Average Price (CAP).

The Gas Reference Price is determined by the Minister for each production month, and is used to value the raw gas, residue gas and ethane for royalty clients who choose the Gas Reference Price method.

The CAP is calculated annually by a royalty client using his own sales for the period. Annually the Department uses the calculated CAP to value the raw gas, residue gas and ethane for those royalty clients who choose the CAP method.

Sch.1 - S.5(3)(4) If a royalty client wishes to use the CAP method, he must file a VA1 form (*Please see Section 22.1*). If a royalty client makes no selection, or is not eligible to use the CAP method, he is deemed by the Minister to have selected the Gas Reference Price method.

A royalty client who has chosen to value his Crown royalty share using the CAP method may subsequently elect to use the Gas Reference Price method. However, if the Gas Reference Price method was chosen initially, the CAP method cannot be selected afterwards.

6.2 Gas Reference Price for Raw Gas

(This section applies to royalty clients who have elected to value their gas at Reference Price.) Raw gas disposed of at **arm's-length*** prior to processing and which is subsequently processed before delivery to a sales pipeline is valued at 80% of the Reference Price. Raw gas that is used as off-site fuel, which would otherwise require processing, is also valued at 80% of the Reference Price.

For all raw gas sales reported on the OAS, if the heat content is known it must be reported. In those instances where the heat content is not known, the Department will use a GJ factor as established by the Minister (currently set at 41 GJ per 10^3m^3).

Sch.1 - S.4(2)(b) The price at which the Department will value the Crown royalty share of raw gas is reduced to provide a **nominal cost allowance*** in recognition of value not yet added by processing but which is reflected in the Gas Reference Price. The allowance is a percentage of the Gas Reference Price as determined by the Minister.

**For definition, please see Appendix N – Glossary*

The Minister has determined that the Department will value raw gas, on which a Crown royalty share has been established, at 80% of the Gas Reference Price for the month in which that liability is established. A valuation of 80% of the Gas Reference Price for the month will apply if the immediate destination of raw gas sale is a gas plant (including field and mainline straddle plants). In all other cases, a valuation of 100% of Gas Reference Price will apply unless it is proven later that the raw gas sales volume is sent to a gas plant for processing or is being used as off-site fuel which otherwise would require processing to meet the pipeline specifications. Such cases should be referred to the Team Leader, Client Services Help Desk, for review. Raw gas sale volumes that are not subsequently processed (excluding raw gas used for off-site fuel), are not eligible for 80% of the Gas Reference Price. Also, raw gas volumes transferred to an injection facility are not eligible for 80% Gas Reference Price valuation because injection credits are valued at 100% of the Gas Reference Price.

Should other situations pertaining to raw gas sale warrant the 80% of the Gas Reference Price valuation, clients may identify these for the Department for review, and if approved, an adjustment to the valuation will be made.

NOTE: THE UOCR WILL NOT BE ALLOWED AS A DEDUCTION ON CROWN ROYALTY DETAIL CALCULATION STATEMENT ON RAW GAS SALES THAT ARE ELIGIBLE FOR 80% GAS REFERENCE PRICE VALUATION. IN ADDITION, THE CROWN WILL NOT SHARE IN CUSTOM PROCESSING FEES CHARGED IN RESPECT TO THE GATHERING, COMPRESSING AND PROCESSING OF RAW GAS VOLUMES.

6.3 Gas Reference Price for Co-Generation and Similar Long-Term Contracts

6.3.1 Election to Grandfather an Existing Contract

Royalty clients electing reference price valuation subsequent to June 15, 1994 are not eligible to grandfather contracts.

Sch.1-S.7(5) A royalty client who has an authorized election to grandfather a contract must determine and report on the GR2 form the monthly deliveries and netback selling prices under that contract on or before March 31 of the year following the year for which the information applies. *(Refer to Sections 14.2 and 22.4).*

Sch.1 - S.7 A royalty client using the Gas Reference Price may elect to value the Crown royalty share of gas delivered under an existing **co-generation*** or similar long-term contract, at the net price *(and/or net value of other considerations)* received under the contract where:

- the contract is in effect on January 1, 1994; *)*
- a written agreement in principle is established on January 1, 1994, and a contract resulting from this agreement is in effect on or before January 1, 1995;
- the price paid is fixed initially and the annual increments are tied to other than a gas index;
- the contract is between parties that are not associates; *and*
- the term of the contract is not less than 10 years and the portion of the term remaining on January 1, 1994, is not less than 3 years

A **novation*** in respect of such a contract will be honoured by the Department; however, renewals of a contract or changes that affect the terms of a contract will not.

Prepaid contracts are not eligible to apply for the grandfathering provision. They will be valued at the Gas Reference Price.

**For definition, please see Appendix N – Glossary*

A royalty client who satisfies the requirements described above may apply to the Department for authorization using a GR1 form *(Refer to Section 22.3)* to value the Crown royalty share of gas delivered under that contract, at the net price and/or net value of other considerations received under the contract if such application is:

- regarding natural gas recovered from or attributable to Alberta Crown minerals upon which there is no outstanding claim by the Crown;
- received by the Team Leader, Client Services Help Desk, on or before June 15, 1994;
- accompanied by a copy of the subject contract and all **collateral agreements*** pertaining to the contract; *and*
- given under the signature and attest of a **corporate signing officer*** of the corporation that is the subject of the application, or the signature and attest of the individual who is the subject of the application, whichever applies.

Where a royalty client is authorized to value the Crown royalty share of gas delivered under a contract at the net price and/or net value of other considerations received under the contract, that valuation method will apply to the full time period stated in the authorization.

6.4 Gas Corporate Average Price (CAP)

Sch.1 - S.6(7) A royalty client who has a valid CAP election must determine and report its CAP annually by April 15 of the year following the year of production. *(Refer to Section 22.2).*

The Department will value and invoice the monthly raw gas, residue gas and ethane Crown royalty share of such a royalty client using an estimated CAP based on the Reference Price in effect during the production month adjusted by the royalty client's Corporate Gas Factor. *(Please refer to Section 14.4.1).*

Annually, the Department will use the CAP calculated by the royalty client to value its Crown royalty share of raw gas, residue gas and ethane for each month of the subject year, and will reflect the adjustment on the royalty client's Crown Royalty Detail Calculation statement.

No interest will be charged or paid to the royalty client on the royalty difference between the estimated monthly CAP and actual CAP determined annually (except in the case of late filing of the first version of the VA2 form when interest will be charged or paid on the difference). Interest will be charged or paid on amendments to the annual adjustments received after the annual adjustments have been reported on the invoice.

For the purpose of raw gas, residue gas and ethane valuation, persons are associated if one person owns or has a beneficial interest equal to or greater than 75% of the other person, whether directly or in combination with other Associates.

6.4.1 Minimum Price for the Gas Corporate Average Price

Sch. 1 – S.6(3) A Gas CAP may not be less than 90% of the weighted average of the monthly Gas Reference Prices for the year to which the CAP applies. *For additional information, please see Section 14.3.3.*

For definition, please see Appendix N – Glossary

6.4.2 Eligibility Criteria Required for Using the Gas Corporate Average Price

To be eligible to use the CAP method, a royalty client must:

- have no Associates who value their Crown royalty share using the Gas Reference Price method; *and*
- not have selected the Gas Reference Price method previously, nor been required to value his Crown royalty share using this method.

Sch.1 - S.5(2) To select the CAP method, a royalty client must file an election for gas valuation on a VA1 forms *(Refer to Section 22.1)* to be received by the Department:

- on or before June 15, 1994, if the person was a registered royalty client prior to 1994; *or*
- on or before the 15th day of the second month following the production month (reported on the OAS or RMF2) in which the person becomes a royalty client after 1993.

6.4.3 Maintaining Eligibility to Use the Gas Corporate Average Price

Sch.1 - S.5(4) to (9) When a royalty client's CAP selection ceases to be valid, the royalty client must use the Gas Reference Price, which becomes effective from the production year in which the client's CAP ceases to be valid. The reasons for invalidating the selection are as follows:

- the royalty client has given written notice on the VA1 form, changing his previous selection (notice to be received by Team Leader, Client Services on or before March 1); *or*
- an associate of the royalty client begins to use the Gas Reference Price; *or*
- the royalty client becomes an associate of another royalty client who uses the Gas Reference Price; *or*
- the royalty client merges or, in the opinion of the Minister, effectively merges his business with that of another royalty client who uses the Gas Reference Price.

If the royalty client or an associate of the royalty client fails to comply with the disclosure and reporting requirements for determining the CAP, royalty clients must use the Gas Reference Price, effective the first day of the year for which the default relates.

Sch.1 - S.5(10) A royalty client contemplating a **merger*** with, or an acquisition of, or a change in its relationship with another royalty client may request an advance ruling on the effect that the contemplated action will have on its eligibility to use CAP. The Department's ruling will be provided within 30 days of the date on which it receives all the information it requires to make the determination. *(Refer to Section 12.)*

For definition, please see Appendix N – Glossary

6.4.4 Corporate Average Price Re-Election

Sch.1 - S.5 Schedule 1, sections 5 (1), (2) and (3) and 7 (1)(b) and (2)(a) of the Natural Gas Royalty Regulation (AR351/93), have been amended. to provide eligible royalty clients a **one-time** opportunity to establish status as a Corporate Average Price filer for purposes of valuing the Crown royalty share of gas (natural gas, residue gas, and ethane). The necessary re-election advice via the VA1 must have been filed with the Department of Resource Development, Gas Royalty Operations **on or before February 15, 1999.**

Eligible Royalty Clients:

Based on 1997 production year gas royalty related information provided to the Department of Resource Development as at November 15, 1998, royalty clients meeting the following necessary conditions had the option to move to the Corporate Average Price valuation methodology for gas produced on and after January 1, 1999:

- Royalty clients that are neither amalgamated nor consolidated with "net" Crown gas royalties paid or payable relative to 1997 production of less than $225,001; or
- Amalgamated royalty clients with aggregated "net" Crown gas royalties paid or payable relative to 1997 production of less than $225,001; or
- Consolidated royalty clients with aggregated "net" Crown gas royalties paid or payable relative to 1997 production of less than $225,001; and
- A VA 1 is filed with the Department of Resource Development (Gas Royalty Operations at **fax # 780-427-3334**) on or before **February 15, 1999.**

Business Rules Related to Eligibility:

- "Net" Crown royalty paid or payable for the 1997 production year does not include consideration of royalty paid bank credits, Sulphur Emission Control Assistance Program (SECAP) credits, royalty deposits, interest paid or collected, penalties or Provisional Assessment.
- Royalty clients coming on-stream in 1997 or 1998 and consequently operating for less than a full production year will have status for purposes of this one-time re-election opportunity determined on a one-off basis. This will typically be done using a simple extrapolation of Crown gas royalty otherwise payable during the period of operations.
- 1999 production will be valued on an interim basis using a Corporate Gas Factor of 1.
- VA2 (for the 1999 production year) to be filed **on or before April 15, 2000.**

Royalty Clients Who Are Part of a Consolidation with 1997 Net Aggregate Crown Gas Royalties Paid or Payable of Less Than $225,001:

In those instances where all Business Associates within the consolidation do not wish to elect to move to Corporate Average Price valuation, a transition provision is to be provided for individual royalty clients who do wish to make such an election. A written request to remove a specific arms-length royalty client from a consolidation effective December 31, 1998 received with or before the VA1 election documentation (filing deadline February 15, 1999) will trigger the re-election opportunity for the then non-consolidated royalty client. Please send your written request to Manager, Help Desk.

Business Rules:

- A royalty client using the Alberta Reference Price valuation methodology can not move to the Corporate Average Price valuation methodology except by way of this one-time re-election opportunity.
- Royalty clients using the Corporate Average Price valuation methodology can move to the Alberta Reference Price valuation methodology by way of a written request in accordance with the Natural Gas Royalty Regulation (AR 351/93) Sch. 1 Section 5(8).
- A royalty client's annual Corporate Average Price will:
  - be subject to a floor value of 90% of Alberta Reference Price,
  - have no upper valuation limitation,
  - be calculated by the royalty client and submitted to the Department of Resource Development via the VA2 on or before April 15 of the year following the production year, and
  - be supported by calculations and documentation for a period of four (4) years subsequent to the end of the production year in question.
- A VA2 filed after April 15 of the year following the production year will be subject to a $1000.00, one-time filing penalty.
- If a VA2 is not filed on or before May 30 of the year following the production year, the royalty client will see their Corporate Average Price filing status permanently revoked.

- In those instances where a royalty client ceases to be a Corporate Average Price filer, either voluntarily or by virtue of the above, Crown royalty charges will be calculated, including applicable interest charges and invoiced for the production year using the Alberta Reference Price.
- In those instances where a VA2 is not filed by May 30 of the year following the production year, the royalty client will be subject to the Department's Compliance and Assurance review, including potential application of Audit penalty provisions (refer to Principles and Procedures Section 10.4).
- In the case of an Amalgamation or Consolidation, all involved royalty clients (Business Associates) will utilize a single gas valuation methodology.
- "New" royalty clients access to Corporate Average Price filer status is detailed in the business rules in the Gas Royalty Principles and Procedures Section 6.4.2.

6.4.5 Sales to Associates to Qualify for Valuation at the Gas Reference Price

In order for sales made to an Associate to qualify for valuation at the Gas Reference Price, the following conditions must be met:

- the Associate must not have any sales of its own. If the Associate does have sales, he must calculate a CAP; and
- the Associate must be purchasing the gas for consumption in his normal operations.

NOTE: CONSUMPTION FOR THIS PURPOSE MEANS GAS PURCHASED FOR INDUSTRIAL USE.

A royalty client who is uncertain about valuing sales to Associates should seek an *Advance Ruling* from the Department. (Refer to Section *12.*)

6.4.6 Audit Access to Associates of Clients Using the Gas CAP

Sch.1 - S.5(5)(b) Where a royalty client's calculated CAP includes sales to an Associate valued at the Associate's CAP, the Associate must consent to an audit of its CAP at the request of the Minister. The royalty client whose Associate is the subject of the audit may elect that the audit be done:

- by the Department, at the Department's expense (manpower salary expense); or
- by an independent auditor, subject to prior approval by the Minister, at the expense of the royalty client.

NOTE: AUDIT RECORDS MUST BE MADE AVAILABLE IN ALBERTA.

If an Associate does not consent to the audit of his CAP, or fails to provide a satisfactory audit trail which leads to transactional data capable of being validated, the royalty client and each of his Associates who are royalty clients will no longer be permitted to value their royalty quantities using CAP effective the first day of the year for which the required data relates.

6.4.7 Including Non-Alberta Sourced Gas in the Gas Corporate Average Price

Where a royalty client's sales include non-Alberta sourced gas, that gas is included in determining the royalty client's CAP except where:

- the non-Alberta gas is not mixed with Alberta gas belonging to the same royalty client at any time prior to being sold; or
- the Minister is satisfied that the arrangements for sale and transportation do not reduce the value of Alberta gas.

Where non-Alberta gas is included in the calculation of a royalty client's CAP, it is subject to the same rules for valuation as if it were produced in Alberta. Specifically, all mixed Alberta and non-Alberta gas must be included in the CAP calculation along with all non-Alberta and Alberta eligible fixed demand and variable demand transportation charges.

6.5 Valuing Gas Products

6.5.1 Valuing Crown Share of Propane and Butane

A.R. 351/93
Sch.4 - S.2, S.3

The Department values and invoices the monthly Crown royalty share of propane and butane based on monthly reference prices that represent the value of **specification product*** delivered at Edmonton. To recognize the different values of propane and butane at the point where the Crown royalty liability is triggered *(the plant gate)*, adjustments are provided for:

- regional transportation cost from the plant gate to Edmonton *(Refer to Section 15.3.1)*;
- 1994 intra-Alberta storage cost related to transportation and fractionation. Storage cost for 1995 onwards is set at $0 per m^3 (Refer to Section *15.3.2*); *and*
- fractionation cost for products produced as a component of an NGL mix (*Refer to Section 15.3.3)*.

****For definition, please see Appendix N – Glossary***

6.5.2 Valuing Crown Share of Pentanes-Plus

Sch.2 - S.2(2)

The Department values and invoices the monthly Crown royalty for pentanes-plus based on the monthly reference price that represents the value of specification pentanes-plus delivered at Edmonton. To recognize the differing values of pentanes-plus at the point where the Crown royalty liability is triggered, adjustments are provided for:

- regional transportation cost from the plant gate to Edmonton *(Refer to Section 15.3.1)*;
- 1994 intra-Alberta storage cost related to transportation and fractionation, for pentanes-plus contained as a component of NGL mix. For 1995 onwards, the storage allowance is set at $0 per m^3 *(Refer to Section 15.3.2);*
- fractionation cost for pentanes-plus contained as a component of NGL mix *(Refer to Section 15.3.3); and*
- **special pentanes processing allowance*** provided on a case by case basis, if approved by the Minister *(Refer to Section 15.3.4).*

6.5.3 Valuing Crown Share of Sulphur

Effective with production month January 1997, all royalty clients having annual sulphur production of 30,000 tonnes or more (based on previous year's production) must choose to file monthly forms to determine their Sulphur Corporate Average Price (S-CAP). Those royalty clients whose annual sulphur production is less than 30,000 tonnes (based on previous year's production) may choose to file monthly forms. *Please see Section 15.4.1 for additional information.*

For definition, please see Appendix N – Glossary

7 Alberta's Royalty Share of Cost Allowances

7.1 Overview

A.R. 351/93
S.17(1)(3)(4)(5)

The Crown deducts allowances for compressing, gathering and processing its royalty share of gas and gas products through the Crown share of Cost Allowances to which the Minister consents.

Unless the Minister directs otherwise, the Crown share of Cost Allowances is deducted only by way of reductions from money owing the Crown for natural gas and gas products royalty.

The Crown share of Cost Allowances deducted for a royalty client in a year may not exceed the total money otherwise owed the Crown for natural gas and gas products royalty for that year. Crown share of Cost Allowances calculated for a year, which are not recovered in that year, *may not* be carried forward to a subsequent year. *(Refer to Section 7.2.)*

There are three types of Crown share of Cost Allowances:

- Crown share of Capital Cost Allowances;
- Crown share of Operating Cost Allowances; *and*
- **Crown share of Custom Processing Cost Allowances***

Crown share of Capital Cost Allowances is determined annually. They are deducted monthly on an estimated basis and adjusted at the end of the year when actual costs are reported and calculated. Crown share of Capital Cost Allowances is deducted for royalty clients who participate in the capital allocation from compressing, gathering and processing facilities.

Unit Operating Cost Rates (UOCR) are determined annually, in advance of the year to which they will apply. Crown share of Operating Cost Allowances are deducted monthly for each royalty client based on his Crown royalty share of gas and gas products in the month and the applicable UOCR.

Crown share of Custom Processing Cost Allowances are determined annually based on processing costs paid in the year. They are deducted monthly on an estimated basis and adjusted at the end of the year. Crown share of Custom Processing Cost Allowances are deducted for royalty clients who pay for compressing, gathering and processing on a ***fee-for-service**** basis.

NOTE: TO FACILITATE ADMINISTRATIVE SIMPLICITY, THE DEPARTMENT WILL ACCEPT ALLOWABLE CUSTOM PROCESSING FEES AND/OR ALLOWABLE OPERATING COSTS AS BEING THOSE PAID IN THE YEAR RATHER THAN FOR THE YEAR UNLESS THE PROCEDURE IS JUDGED TO SIGNIFICANTLY DISADVANTAGE THE CROWN. THIS PROCEDURE WILL ELIMINATE RETROACTIVE FILING WHEN FEES ARE BILLED AFTER THE DUE DATE FOR FILING OF THE AC5 FORM. ROYALTY CLIENTS MAY MAKE PRIOR PERIOD ADJUSTMENTS AGAINST THE CURRENT YEAR REPORTING AS LONG AS THE FACILITY IS NOT TERMINATED OR THEY HAVE NOT SOLD OR ACQUIRED AN INTEREST IN THE FACILITY. ALL ADJUSTMENTS MUST INCLUDE BOTH VOLUMES AND COSTS. IF THE FACILITY IS TERMINATED OR THEY HAVE SOLD OR ACQUIRED AN INTEREST IN THE FACILITY, THE ROYALTY CLIENTS MUST AMEND THE APPROPRIATE YEAR'S AC5 FORM. ONCE A METHOD OF REPORTING HAS BEEN DECIDED UPON FOR A FACILITY, THIS MUST BE APPLIED CONSISTENTLY FROM YEAR TO YEAR. THE DECISION OF THE BRANCH HEAD, GAS OPERATIONS WILL BE CONSIDERED FINAL IN RESPECT OF ANY ISSUES PERTAINING TO THE INTERPRETATION AND APPLICATION OF THIS BUSINESS RULE.

*For definition, please see Appendix N – Glossary

7.2 Allowable Cost Restriction

Introduction

The Crown share of Cost Allowances is deducted only by way of reductions from money owing to the Crown for gas and gas products royalty. Therefore, the Crown share of Cost Allowances deducted for a royalty client in a year may not exceed the total money owed to the Crown for natural gas and gas products royalty for that year. Crown share of Cost Allowances calculated in respect of a year may not be carried forward to a following year.

Monthly Allowable Cost Restriction

The monthly Allowable Cost Restriction amount will be calculated at a corporate level based on the following items reported monthly on the invoice:

- Crown Royalty
- Monthly Proprietary Waiver
- Monthly Capital Cost Deduction
- Monthly Custom Processing Fee Deduction

Annual Allowable Cost Restriction

The annual Allowable Cost Restriction amount will be calculated at a corporate level based on the following items:

- Annual Crown Royalty Amount
- Annual Proprietary Waiver Amount
- Annual Co-Generation Contract Adjustment Amount
- Actual Annual Capital Cost Deduction
- Actual Annual Custom Processing Cost Deduction

To trigger allowable cost restriction, the sum of the above items (monthly or annual) must be a negative amount. To the extent that the negative Crown royalty results from deductions of allowable costs, the allowable cost restriction will be that amount of the allowable cost which will bring the negative Crown royalty to zero (0); or that amount which reduces the negative Crown royalty amount in proportion to the total allowable costs deducted.

8. Other Programs Administered with Natural Gas Royalty

8.1 Field Condensate Royalty

For Crown royalty purposes, *field* condensate is defined as "*products obtained from natural gas or* ***solution gas**** *before they are delivered to a gathering system*".

Typically, *field condensate* is separated from gas in the field and sold or otherwise disposed of without further processing before entering a gas gathering system.

A.R. 351/93
S.8(4)

Field condensate is subject to Crown royalty under the Petroleum Royalty Regulation *(A.R. 248/90)*. The Crown royalty share of field condensate is determined by the Petroleum Royalty formula. The valuation of that share is under the Natural Gas Royalty Regulations.

Please see Section 17.1.

8.2 Sulphur Emission Control Assistance Program (SECAP)

The *Sulphur Emission Control Assistance Program (SECAP)* is designed to encourage and support environmental protection through the efficient:

- recovery of sulphur from sour and **acid gas***;
- disposal of acid gas at the plant by injection through a well to an underground formation, or the disposal of acid gas at the plant by transporting it by pipeline to another plant for processing.

Through *SECAP*, the Department pays 50% of the incremental capital and operating costs incurred in eligible processes that reduce the sulphur emissions from small sour gas plants.

Please see Sections 17.4 and 20.6.

For definition, please see Appendix N - Glossary

9. Levying and Collecting Natural Gas Royalty

9.1 Royalty Client Accounts

The Royalty Client Account referred to in the Regulation is called **Gas Account*** in the Guidelines for administrative reasons only.

A.R. 351/93
S.15(4)

The Department will establish a *Gas Account* for each royalty client. Charges will be recorded into the client's Gas Account for the following revenue types:

- royalty;
- royalty deposit;
- interest;
- penalties; *and*
- fees

For a more complete description of Royalty Client Accounts, please see Section 25.

9.2 Monthly Statement / Invoice Package

The Department will issue a *statement of account, an invoice and the Crown Royalty Detail Statement* to each royalty client for each **billing period*** in which there are gas royalty transactions, or in which the royalty client has other than a zero balance in its Gas Account with the Department.

The monthly ***statement of account**** describes a royalty client's monthly activity and account balances for each revenue account, summarized by production year.

The monthly ***invoice*** shows a royalty client's activity separately for each **charge type*** and corporate item.

The monthly ***Crown royalty detail**** *statement* reports transactions by:

- royalty client;
- EUB facility;
- charge types;
- production month; *and*
- *Well/Well Group/Unit/Injection Scheme.*

A more complete description of the monthly statement/invoice package is provided in *Section 25.*

9.2.1 Statement of Account, Invoice and Crown Royalty Detail Summary Redesign

The Department has modified the Statement of Account, Invoice and Crown Royalty Detail Summary. These modification were reflected in the March 1998 Information Bulletin. *(Please refer to Section 25.3.1 and 25.4.1.)*

For definition, please see Appendix N - Glossary

9.3 Monthly Royalty Invoice and Payment

S.15(1) The following time lines apply to the statement/invoice package:

• **Invoice issue due date**	on or before the last day of the second month following the production month
• **Crown Royalty Detail Statement issue due date**	on or before the last day of the second month following the production month
• **Statement issue due date**	on or before the 15th day of the third month following the production month
Invoice payment due date:	
(1) Current Period Changes	on or before the last day of the third month following the production month
(2) Prior Period Changes	payment are past due (Interest will accrue until paid)

If the due date falls on a weekend or a holiday, the next business day will apply. *Please see Section 25.*

9.4 Royalty Deposit Account

S.18(1)(a) The Crown requires that a royalty client maintain a deposit on account with the Department that is equal to $^1/6$ *(one-sixth)* of the total net Crown royalty paid in the previous year. For 1994, deposits are payable in two equal payments, the first on or before February 28, 1994, and the second on or before March 31, 1994. For 1995 and following years, the Department will calculate the deposit requirement as part of the year-end transactions and will invoice any debit or credit adjustment to a client's *Royalty Deposit Account* (*Please see Section 18.5*).

The Crown will not pay interest on the deposit maintained with the Department. Also, interest will not be charged nor paid on the annual deposit adjustments. Interest will be charged on late payments or underpayments of invoiced deposit amounts.

S.18(4) If a royalty client disposes of, or acquires properties that make a significant cash flow impact, a written application to adjust the royalty deposit may be made to the Team Leader, Client Services Help Desk. If the application is approved, the Department will adjust the deposit. If the Department determines that the amount of the adjustment is sufficient to warrant an offsetting adjustment, the Department will require that the royalty client(s) who acquired the disposed properties adjust their deposit(s) accordingly (*Please see Section 25.7.7*).

The deposit requirement varies for a person who becomes a royalty client after 1992:

- S.18(1)(b) if a person becomes a royalty client during 1993, but not for the full 12 months, the royalty deposit will be equal to twice the person's average monthly net Crown royalty paid in 1993;
- S.18(3) if a person becomes a royalty client in 1994 or thereafter, the Department will invoice that royalty client for a royalty deposit. The deposit will be equal to the first and second month net Crown royalty payable by the royalty client and will be invoiced in those same months. The deposit will be equal to the first and second month's net Crown royalty and will be invoiced in those same months.

In subsequent years, the normal deposit calculation rules will apply. *For additional information on Royalty Deposit and Statement of Accounts, please see Section 25.3.*

9.4.1 Royalty Deposit Calculation

The royalty deposit for a new royalty client will be determined from the following items reported on the invoice:

- Crown Royalty
- Monthly Proprietary Waiver
- Monthly Capital Cost Deduction
- Monthly Custom Processing Fee Deduction
- Allowable Cost Restriction
- Injection Credits
- Crown Royalty Paid Bank Settlement

The annual royalty deposit amount will be calculated from the following items:

- Annual Crown Royalty
- Annual Proprietary Waiver
- Actual Annual Capital Cost Deduction
- Actual Annual Custom Processing Fee Deduction
- Annual Co-Generation Contract Adjustment Amount
- Annual Allowable Cost Restriction Amount
- Annual Injection Credits
- Annual Crown Royalty Paid Bank Settlement

Annual royalty deposit adjustment will be determined by taking the difference between the new royalty deposit amount and the previous royalty deposit amount.

9.5 Interest Receivable and Payable

S.25(1) The Department will charge interest on underpayments or late payments of invoiced amounts starting on the first day following the invoice due date, and continuing until the date the payment is received.

The Department will charge interest resulting from adjustments to invoiced amounts starting the day following the issue date for the production month, and continuing until the issue date of the invoice on which the adjustment appears.

S.25(3) The Department will pay interest resulting from adjustments to invoiced amounts starting the day following the due date for the production month, and continuing until the date of the invoice on which the adjustment appears.

No interest will be calculated on initial annual estimate-to-actual adjustments, except if the forms are received subsequent to the initial annual processing when interest will be charged or paid on the difference. However, for initial annual sulphur valuation adjustments, interest will be charged or paid on the difference. In all cases, interest will be charged or paid on amendments to annual adjustments commencing the day following the due date for the initial invoice.

S.15(5) The Department will not pay interest on overpayments of invoiced amounts. Effective August 1998 calendar month, prior period credits will no longer be automatically refunded. In order to receive a refund, the "Request for Refund" form must be completed and forwarded to the Department. Once this form is received, refunds will be issued when a royalty client's Statement of Account is in a credit balance and there are no outstanding debts payable to the Department. When refunds are no longer required, the field labeled "Termination of Refund Request" must be completed on the **"Request for Refund"*** form and forwarded to the Department. All refunds will be issued through direct deposit if banking information of the company is established with any Department of the Provincial Treasurer.

If your company does not already receive refunds by direct deposit, please complete and forward a **"Vendor Maintenance Request Form"*** to ensure that this information is established. These forms are intended for the sole use of Gas Royalty refunds.

*The *Request for Refund* and *Vendor Maintenance Form* can be found in Appendix P.

S.25(4) Interest that is receivable or payable by the Department will be calculated at the prime lending rate charged by the Alberta Treasury Branch on the first day of the month for which the interest is being calculated, *plus 1%.*

9.6 Changes to Interest on Prior Adjustments

Commencing with the May 1998 invoice, which was produced in the July 1998 calendar month, the following changes have been implemented:

- The due date for prior period charges is extended to the invoice **due** date rather than the invoice issue date. This will allow both current period and prior period charges to be paid by the invoice due date without current period interest implications. Current period interest on prior period adjustments are not charged if the outstanding balance is PAID IN FULL by the invoice due date.
- Interest is **charged** on *prior period charges* and interest **paid** on *prior period credits* from the day after the **original invoice issue date** to the current invoice issue date. Previously, prior period interest was charged and paid from the **original invoice due date** to the current invoice issue date.
- Current Period Interest will continue to be assessed on any late or underpaid amounts.

9.7 Application of Payments to Royalty Client Revenue Accounts

S.26 If a client's Gas Account has an outstanding balance for two or more production months; a payment received from that royalty client will be applied to the old outstanding balances, starting with the oldest. Clients with outstanding balances on pre-1994 and post-1993 royalties must allocate payments separately to these accounts.

Unless the Minister directs otherwise, monies received for credit to a royalty client's *Gas Account* will be applied to *revenue account* balances as follows:

- *first,* to the *Fees Account;*
- *second,* to the *Penalties Account;*
- *third,* to the *Interest Account;*
- *fourth,* to the *Royalty Deposit Account;* and
- *fifth,* to the *Royalty Account. (Please see Section 25).*

9.8 Collecting Outstanding Accounts

Where an amount has been levied against a royalty client's *Gas Account*, and that amount or a portion of it has not been paid by the due date specified on the relevant Invoice, the Department will take action to collect the outstanding amount.

The Department's action will be in four separate stages, and will continue until the entire outstanding amount is collected. The four stages are:

- If balance is not paid by due date..... *Notice is issued to royalty client on the Statement of Account*;
- If balance is outstanding for **30 days**..... *Notice is given on the Statement of Account and Potential Recourse Letter is issued to the royalty client;*
- If balance is outstanding for **60 days**.... *Leaseholder Recourse Letter is issued to leaseholders and a* letter is sent to Alberta Corporate Tax to transfer any **ARTC*** refund due the royalty client to the Department. In addition, if the royalty client is named on the lease, the Department will freeze the lease (i.e. the Department will not consent to a sale or transfer of the lease);
- If balance is outstanding for **90 days**.... *Department will notify leaseholders that they have 30 days to make payment or face lease cancellation.*

9.9 Determining Leaseholder Liability

The Department will attach outstanding liabilities to leases and leaseholders in order to apply its collection procedures using the following principles:

If a royalty client who is the subject of an action by the Department for collecting an outstanding balance has more than one lease, the Department will determine which leases are subject to action by:

- allocating the outstanding balance to the royalty client's *Wells/Well Groups/Units/Injection Schemes* for the month to which the default relates;
- allocating the outstanding balance to the well events within the *Wells/Well Groups/Units/Injection Schemes* based on EUB production data and adjusted for Crown interest; *and*
- associating the outstanding balance at each well event with the Crown lease agreement for that well event

(For definition, please see Appendix N - Glossary)

10. Enforcing Compliance with Legislation and Policy

10.1 Overview

The Department's ability to issue complete, accurate and timely Crown royalty invoices depends upon the reliability and timeliness of information provided by royalty clients, Facility Operators, designated purchasers, and the operators of designated storage facilities.

The risk associated with inaccurate statements that result in underpaid Crown royalty, and the administrative cost of detecting and correcting such deficiencies, is reflected in the penalties described in *Section 10.4.*

10.2 Assessment and Levy of OAS Reporting Discrepancies

A.R. 351/93
S.22(1)(4)

Where a Facility Operator does not fully account for all the quantities for which he is responsible in a month, the Department will:

- notify the Facility Operator of the discrepancies;
- deem that Facility Operator to be a royalty client with respect to the quantities that are not accounted for;
- calculate a ***provisional royalty**** for these quantities; *and*
- charge that provisional royalty on the Facility Operator's invoice.

A detailed description of the *provisional royalty* calculation and assessment procedure is provided in *Section 26.1.*

The Department considers that quantities are not fully accounted for if:

- .21(8) an OAS is not filed for a facility, in which case the Facility Operator is deemed to have filed a *nil* OAS report;
- S.22(1) an OAS is filed for a facility; however, the Facility Operator does not allocate all quantities;
- S.22(2) the quantities reported to EUB for a facility exceed the quantities reported to the Department for the same facility; *or*
- S.22(3) the quantities reported as purchased at a facility exceed the quantities reported as sold. In this case, the operator of the facility who reported the sale will be provisionally assessed.

S.22(5) If the Facility Operator is assessed a provisional royalty and in a subsequent month the operator accounts for all or part of the deficient quantities, the Department will reverse the original provisional assessment amounts and prior period interest charged up to the original provisional assessment invoice issue date. Current period interest charged after the original provisional assessment invoice issue date will not be reversed.

A detailed description of the *volumetric reconciliation* procedure is provided in *Appendix A.*

For definition, please see Appendix N – Glossary

10.3 Late Filing Penalties

The Department will assess penalties against persons who file the forms after the prescribed deadlines, or who do not file the forms required by the *Natural Gas Royalty Regulation, 1994*. The forms that are not system acceptable will be rejected and treated as not received. Penalties will be charged if these forms are not re-submitted by the prescribed deadlines.

S.24(1)(2)(3) For production year 1994, the penalty for failing to file a form acceptable to the Department by the due date is $1,000 for each calendar month or part of a calendar month during which the failure continues. *(Refer to Section 26.4.)*

The following are the forms to which the penalty applies and the person who will be charged.

	Well Group Setup/Change (RMF1)	FACILITY OPERATOR
	Reassignment of Volumes Setup/Change (RMF2)	ROYALTY CLIENT
	Single Well/Injection Scheme Setup/Change (RMF3)	OPERATOR
	Owner Activity Statement (OAS)	FACILITY OPERATOR
(1)	Annual Corporate Average Price Calculation - Gas (VA2)	ROYALTY CLIENT
	Monthly Corporate Average Price Calculation - Sulphur (VA4)	ROYALTY CLIENT
(2)	Annual Corporate Average Price Calculation – Sulphur (VA3)	ROYALTY CLIENT
(3)	Annual Statement of Grandfathered Contract Sales (GR2)	ROYALTY CLIENT
	Annual NGL Valuation (NGL1)	DESIGNATED OPERATOR
	Annual NGL Storage Costs (NGL2)	DESIGNATED OPERATOR
	Allowable Costs - Facility Cost Centre Set-up/Change (AC1)	FACILITY OPERATOR
	Allowable Costs - Capital Costs (AC2)	FACILITY OPERATOR
	Allowable Costs - Capital Reallocations (AC3)	ROYALTY CLIENT
	Allowable Costs - Operating Costs (AC4)	FACILITY OPERATOR
	Allowable Costs - Custom Processing Fees Paid (AC5)	ROYALTY CLIENT

(1) If a royalty client's Gas Corporate Average Price calculation is in default for four consecutive months after the due date of April 15, the CAP election made by defaulting royalty client and associates ceases to be valid effective the first day of the year to which the default relates, and the Gas Reference Price will be used to value their **Crown royalty volumes**[*]. A penalty of $1,000 per calendar month or part of a calendar month will be charged to the royalty client for the default period April 15 to August 15.

If a Gas Corporate Average Price calculation is in default for two consecutive months, the Department will give written notice to the defaulting royalty client and his associates.

(2) If a royalty client who is required to submit annual Sulphur Corporate Average Price calculation (VA3) is in default for three consecutive months after the due date of April 15, the Department will value the Crown royalty share of that royalty client's volumes using the annual Sulphur Default Price for the period to which the VA3 applies. A penalty of $1,000 per calendar month or part of the calendar month will be charged to the royalty client from the due date of the form until the form is received by the Department.

Upon receipt of the royalty client's VA3, the Crown royalty share will be valued in the manner described in Section 15.4.

If a Sulphur Corporate Average Price calculation is in default for two consecutive months, the Department will give written notice to the defaulting royalty client.

(3) If a royalty client's Annual Statement of Grandfathered contract sales is in default for four consecutive months after the due date of March 15, the royalty client loses the election to grandfather co-generation or long-term contracts. The volumes subject to these contracts will be valued at the applicable monthly Reference Price. A penalty of $1,000 per calendar month or part of a calendar month will be charged for the default period March 15 to July 15.

[*] ***For definition, please see Appendix N - Glossary.***

10.4 Current Late Filing Penalties

Effective January 1999, a change to the late filing penalty structure was implemented. These changes were superseded in November 1999 when the Department of Resource Development enhanced the penalty process to maintain consistency and fairness among royalty payers who submitted reports by the due date, those who received and paid penalties, and those who never submitted reports that are now past due.

Changes to the penalty administration are:

1) Once a report became overdue, a late filing penalty accrued for the first and each subsequent month or partial month it remained overdue. The Department charged the penalties that have so accrued from the beginning of 1995 that had not been previously charged, whether or not the reports had been received. This differed from the previous administration under which penalties, although accruing monthly on an overdue report, were only charged upon receipt of the report.
2) All late filing penalties so charged were adjusted to bring them in line with the 'new' penalty rules introduced in January 1999. Likewise, late filing penalties charged and paid for 1995 to 1998 were adjusted to bring them in line with the new penalty rules.
3) The Department waived any uncharged late filing penalties that accrued for the 1994 production year. Late filing penalties charged and paid for 1994 were not adjusted or reimbursed.
4) Prior period interest was not charged on the penalties that accrued but were not charged previously. Prior period interest was not paid on any refund of a penalty arising from an adjustment that resulted in a reduction of a penalty previously charged and paid.

		Production Year 1994		**Production Year 1995 and Onwards**		
Form	**Purpose**	**Filed**	**Penalty**	**Filed**	**Penalty**	**Person Charged**
AC1	Facility set-up/operator change	As required	$1000/mth	As required	NIL	Facility Operator
AC2	Allocation of capital	Annual	$1000/mth	Annual	$100	Facility Operator
AC3	Further capital allocation	Annual	$1000/mth	Annual	NIL	Royalty Client
AC4	Operating costs (large 38)	Annual	$1000/mth	Annual	$1000	Facility Operator
AC5	Custom Processing claims	Annual	$1000/mth	Annual	$100	Royalty Client
RMF1	Well group set-up	As required	$1000/mth	As required	NIL	Facility Operator
RMF2	Further volume allocation	As required	$1000/mth	As required	NIL	Royalty Client
RMF3	Injection group set-up	As required	$1000/mth	As required	NIL	Operator
VA2	Corporate Avg. Price –gas	Annual	$1000/mth	Annual	$1000	Royalty Client
VA3	Corporate Avg. Price – sulphur	Annual	$1000/mth	Annual	$1000	Royalty Client
VA4	Monthly sulphur values	Monthly	$1000/mth	Monthly	$100	Royalty Client
NGL1	NGL values/transportation	Monthly	$1000/mth	Monthly	$1000	Designated Operator
GR2	Co-Gen Contracts	Annual	$1000/mth	Annual	$1000	Royalty Client

**The valuation election is revoked and the client will be defaulted to the Reference Price.*

10.5 Penalties on Inaccurate Statements in a Required Report

S.24 (5) If the Department determines, through an examination of records or otherwise, that the Crown **royalty compensation*** payable by a royalty client for a production year has been underpaid, the Department may impose a penalty equal to 10% of the underpayment of the principal amount. A simple mathematical error will not result in a penalty assessment. Errors made by a royalty client in good faith based on information provided by another person(s) required to report that data, will not be assessed a penalty for that error under *Natural Gas Royalty Regulation, 1994 (NGRR, 1994) Section 24(5).*

If an underpayment is discovered, whether or not a penalty is imposed, the Department will notify the royalty client of the deficiency that it believes is the cause of the underpayment, and specific reference will be made to the guideline and/or regulation breached.

S.24(6) *If* a notice of deficiency has been given, and the Department determines that:

- the Crown royalty compensation in a subsequent production year has been underpaid; *and*
- the cause is the same or similar to the cause stated in the notice,

then the Department may impose a penalty of up to 50% of the underpayment of the principal amount that is attributable to the cause stated in the notice.

A royalty client will be given 12 months from the date of a notice to correct any similar errors in subsequent periods before a penalty in excess of the 10% rate will be applied.

The minimum penalty for underpayment of Crown royalty is $1,000. This penalty assessment will be measured against the total amount of all penalties resulting from the inaccurate statement(s).

A penalty assessed for underpayment is in addition to any Crown royalty compensation and interest that is otherwise payable.

10.6 Close-Out for Operations

To contain the extent of retroactive processing and to facilitate the completion of audits within the legislated time frames, an Operational Close-out process has been established. Two years after the end of a production year, the production year is operationally closed. For an operationally closed year, the Mineral Revenues Information System (MRIS) will reject any royalty document submitted, unless written authorization is granted by the Department.

Should circumstances warrant the amending of documents for a closed out year, a written request must be made which includes the following detailed information:

1. Specific reason for processing documents after operational close-out.
2. List of documents types being amended (i.e., OAS, RMF2, AC2).
3. Affected facilities and/or stream IDs (i.e., Gas Plant code, facility cost centre code, well event).
4. Concurrence from all affected parties (i.e. *Cascades on an OAS, RMF2's*).
5. Estimated dollar impact.
6. Paper copies of the document(s) to be processed.

Written requests together with the applicable royalty documents must be submitted to the Manager, Help Desk.

*For definition, please see Appendix N – Glossary

11. Rights and Assurances of Royalty Clients

11.1 Audits of Department Calculation of Royalty Variables

A.R. 351/93
S.27 (1)(a)

Subject to a prior arrangement with the Department, a recognized petroleum and natural gas industry association may appoint an auditor to conduct a review of the Department's compliance with legislation and policy governing the calculation of certain Crown royalty variables.
The Department recognizes the following petroleum and natural gas industry associations for this purpose:

- Canadian Association of Petroleum Producers (CAPP); *and*
- Small Explorers and Producers Association of Canada (SEPAC).

To be acceptable to the Department, an auditor appointed by either CAPP or SEPAC must meet the legal and institutional requirements to practice in Alberta.

S.27(1)(b)(i)

The Department records that are subject to an independent audit by industry are those related to determining:

- Gas Par Price/Reference Price,
- Propane Reference Price,
- Butane Reference Price,
- Pentanes Reference Price,
- Pentanes Par Price,
- NGL Fractionation Allowances,
- NGL Transportation Allowances,
- NGL Storage Allowances,
- Sulphur Default Price,
- Unit Operating Cost Rates,
- Propane Floor Price,
- Butane Floor Price, *and*
- Provincial Weighted Average Gross-Up Factor.

S.27(1)(b)(ii)

In addition, the Ministry records related to the Gas Reference Price prescribed by the Minister are subject to the same right of audit.

The Minister may expand the list of Department records that are subject to an independent audit.

S.27 (4)

Information obtained from the records of the Ministry is confidential. It may be used by the auditor to prepare a report to the association that appointed it, subject to the terms of the arrangement with the Department. Generally, the report will:

- express an opinion on the reliability of the Department's calculation of a prescribed royalty variable;
- identify any errors discovered; *and*
- estimate the overall effect the errors might have on a royalty variable.

S.27(2)

The association(s) that arranged for the audit is responsible for its payment.

The Department will undertake to provide a copy of the Management Report to the association that arranged the audit as soon as practicable within the confines of confidentiality and privacy.

11.2 Disposition of Errors Discovered in an Independent Audit or Internally by the Department

The Department will adjust errors discovered in an independent audit or internally within the Department according to the amendment rules established for the Crown royalty variable that contains the error.

No adjustment will be made for errors discovered in an independent audit more than two years after the end of the production year to which the error applies.

12. Advance Rulings and Appeals

12.1 Advance Ruling Process

An *Advance Ruling* is a statement by the Department describing how it will interpret the applicable laws, policies and guidelines with respect to certain proposed business arrangements. The Department will act according to its *Advance Ruling* for a given proposal except where circumstances dictate otherwise. A description of such circumstances is provided later in this section.

12.1.1 Basic Concepts

The basic concepts relating to *Advance Rulings* are:

- The Department will consider an *Advance Ruling* only for business arrangements that are being seriously considered by a royalty client.
- An *Advance Ruling* will be considered only for proposals with significant dollar impact for *either* the royalty client or the Crown.
- An *Advance Ruling* applies only to the specific business arrangement for which it is issued, and may be subject to qualifications.
- An *Advance Ruling* will apply only to administrative matters within the Mineral Operations Division and *will not* constitute a ruling, advice or other commentary on other aspects or consequences of an opposed business arrangement.
- The issuing of an *Advance Ruling* is based on full disclosure of all facts, authorities and other matters that relate to the proposed business arrangement that is the subject of the *Advance Ruling*.
- Opinions or interpretations to existing arrangements are not considered to be advanced rulings.
- Opinions are subject to review and are not binding in the same way as *Advance Rulings*.

12.1.2 Request for an Advance Ruling

This must clearly be identified as a *"Request for Advance Ruling"*, signed by an authorized representative of the royalty client making the request and submitted to the Director of Interpretations (Royalty and Tenure Policy).

12.1.3 Statement of Issues

A *Request for Advance Ruling* must clearly state all the issues relevant to the proposed business arrangement on which a ruling or rulings are requested.

12.1.4 Statement of Facts

A *Request for Advance Ruling* must provide a clear, detailed and separate statement of all material facts. A reference to *relevant facts* contained within other materials accompanying a *Request for Advance Ruling* is not sufficient.

12.1.5 Statement of Purpose

A *Request for Advance Ruling* must provide a clear statement(s) of the purpose of the proposed arrangement.

12.1.6 Royalty Client's Analysis

A *Request for Advance Ruling* must provide:

- a comprehensive analysis of the effect that each of the relevant facts has on the issue(s) involved;
- detailed references to the relevant provisions of the enactments and other authorities having a bearing on the issue(s) involved; *and*
- the royalty client's interpretation of the enactments and other authorities that form the basis of the analysis.

12.1.7 Initial Review

Following the initial review of the material provided with a *Request for Advance Ruling*, the Department may request additional information or clarification of certain material provided by the royalty client. Any such information or clarification must be provided to the Department before the review will proceed.

12.1.8 Withdrawal of a Request

A *Request for Advance Ruling* may be withdrawn at any time before a ruling is issued. The Department will retain all materials provided with respect to the Request for Advance Ruling.

12.1.9 Processing a Request

Requests for *Advance Rulings* will generally be handled in the order in which they are received. Wherever possible, the Department will provide a royalty client with an estimate of the time required to consider a request and issue an *Advance Ruling*.

12.1.10 Advance Rulings Ceasing to Have Effect

The Department may *retroactively* revoke an *Advance Ruling* where:

- material has been misrepresented or omitted in the Statement of Facts, Statement of Purpose or any other representation made to the Department about the proposed business arrangement which is the subject of the *Advance Ruling*; *or*
- there is material disparity between the facts of the proposed business arrangement, upon which the Department made its ruling, and the facts of the business arrangement that actually transpired.

The Department may *prospectively* revoke an *Advance Ruling* where:

- the law upon which the *Advance Ruling* is based is changed, in which case the *Advance Ruling* ceases to be effective on the date of the change to the law;
- the *Advance Ruling* is based on an interpretation of the applicable law and that interpretation is changed by a court decision, in which case the *Advance Ruling* ceases to be effective on the date of the court decision; *or*
- government policy is changed, in which case the *Advance Ruling* ceases to be effective as of the date on which the royalty client is notified.

12.2 Appeals Process

An *Appeal* is the result of a disagreement between a royalty client and the Department with respect to compliance with legislation, Crown agreement, established guidelines or policy and which remains unresolved despite negotiations with the Department's operating staff. Preliminary attempts to resolve a disagreement with operating staff must occur before the Department will accept an appeal.

The **appeals process*** described here *excludes* freehold mineral tax appeals under *Section 4* of the *Freehold Mineral Rights Tax Act.*

12.2.1 Attempts to Resolve a Disagreement

If a royalty client does not agree with a decision received from the Department, the royalty client must contact the relevant operating branch to obtain an explanation of that decision. Such an explanation may be requested by telephone, in writing or in person. The royalty client must attempt to clarify and resolve the disputed decision with the appropriate operating branch before a *Notice of Appeal* is prepared for consideration by the Department.

A decision made by the relevant operating branch will be communicated to the royalty client in writing and will be identified as either an *Operating Decision* or an *Audit Assessment*, depending on the situation.

12.2.2 Notice of Appeal

A royalty client who is unable to resolve a disagreement through discussion with the relevant operating branch may formally object to an *Operating Decision* or an *Audit Assessment* by filing a *Notice of Appeal* with the Director of Appeals (Royalty and Tenure Policy).

A *Notice of Appeal* must be identified clearly as such, and must:

- be received within 90 days from the date the subject *Operating Decision* or *Audit Assessment* is issued;
- clearly describe the reason(s) for the appeal and all relevant facts;
- be regarding an amount that has been paid to the Crown. *A royalty client must pay any outstanding amount related to an Operating Decision or an Audit Assessment either before or simultaneously with a Notice of Appeal or that notice will be rejected.*

For definition, please see Appendix N - Glossary

12.2.3 Information Required in a Notice of Appeal

A *Notice of Appeal* must include the following:

- a description of the *Operating Decision* or *Audit Assessment* that is the subject of the appeal, along with how, when and by whom it was originally communicated to the royalty client;
- a brief description of the attempts made by the royalty client to resolve the disagreement with operational management;
- the reasons for the appeal;
- evidence in support of the appeal, including:
- a comprehensive analysis of how each of the relevant facts and legislation affect the issue(s) involved,
- detailed references to the relevant legislation and other authorities, *and*
- the royalty client's interpretation of the relevant legislation and other authorities.
- evidence that any outstanding amount related to the *Operating Decision* or *Audit Assessment* that is the subject of the appeal has been paid to the Crown.

A *Notice of Appeal* that does not provide the required information, *to the satisfaction of the Director of Appeals (Royalty and Tenure Policy),* will be rejected.

12.2.4 Review of a Notice of Appeal

The Director of Appeals (Royalty and Tenure Policy) will notify the royalty client in writing that a *Notice of Appeal* has been received. Following the initial review of an appeal, the royalty client may be requested to provide additional information or clarification of information usually within 30 days of receipt of the *Notice of Appeal.* Any such information or clarification must be provided in order for the review to proceed.

Investigation of a *Notice of Appeal* will involve consultation with the royalty client and representatives of the Department operating staff.

12.2.5 Ruling in Respect of a Notice of Appeal

The Director of Appeals' final decision concerning an appeal will be communicated in writing to the royalty client when the investigation and review are completed.

The Department may disclose the issues involved in the appeal and the results of its ruling if this information is considered to be of general application.

Normally the Crown pays interest on the amount in question if the appeal is found in favour of the royalty client.

For definition, please see Appendix N - Glossary

13. Amalgamations and Consolidations

13.1 Amalgamations (Includes Take-Overs and Mergers)

In the event of an amalgamation, a Certificate of Amalgamation must be sent to the Department for its records. If the Certificate of Amalgamation is received by the Department on or before the 15th day of the second month following a production month, then, for Crown royalty purposes, the first day of that production month will be recognized as the effective date of the amalgamation. For example, if Company A amalgamates with Company B on the 26th day of production month of June and the Department receives the Certificate of Amalgamation on or before August 15, the effective date of the amalgamation is June 1.

If the Certificate of Amalgamation is received after the 15th day of the second month following a production month, then, for Crown royalty purposes, the first day of the next production month will be recognized as the effective date of the amalgamation. In the above example, if the Department receives the Certificate of Amalgamation after August 15, the effective date of the amalgamation will be July 1.

All clients who are in the process of, or planning a future amalgamation must request an invoice consolidation prior to the effective billing period of the amalgamation.

13.1.1 Reporting

The amalgamating parties may report separately under their own respective IDs, or under one royalty client's ID. If reporting is done under one royalty client's ID, the royalty client may request to terminate all the other IDs. If the Department approves the request, the IDs will be terminated and the clients will be notified of the terminations.

13.1.2 Valuation

If the gas valuation structure of the royalty clients consists of both CAP and Reference Price, the gas valuation of the amalgamating parties will revert to the Reference Price effective the first month of the year following consolidation *(Refer to Section 6.5.2).*

If the gas valuation structure of the royalty clients consists of only CAP, the gas valuation of the amalgamating parities shall remain CAP as long as their eligibility is maintained. *(Refer to Section 6.5.3).*

13.1.3 VA2, VA3 and VA4 Forms

The amalgamator for the amalgamated entity is responsible for submitting VA2, VA3 and VA4 forms for all amalgamated companies. To do this, they must compile all information for the affected companies and place the combined totals on a VA2/VA3/VA4 form. The VA2/VA3 totals apply for the whole year of amalgamation, regardless of which month the amalgamation took place. The calculated annual Gas Corporate Average Price (CAP) and monthly/annual Sulphur Valuation Price (Sulphur Corporate Average Price (S-CAP) or Sulphur Default Price) will be the same for all companies within the consortium. If the gas valuation structure for all the amalgamating parties consists of CAP, the calculated Corporate Gas Factor (CGF) will be the same for all companies within the consortium.

Only one VA2, VA3 and VA4 form is required, including any amended forms, under the name and ID of the amalgamator for the amalgamated entity *(Please see Sections 22.2, 23.3 and 23.4).*

13.1.4 Allowable Costs

After the amalgamation date, all royalty clients in the consortium may continue to report and receive allowable costs. The amalgamation affects the Corporate Effective Royalty Rate (CERR) calculation.

13.1.4.1 CERR for the Amalgamation Year

From the amalgamation date to the end of the year, the amalgamator's CERR will be used to estimate the allowable costs for deduction from the royalty amount of all the amalgamating parties.

If the amalgamator does not have a CERR, the Provincial Average CERR for the year of amalgamation will be used to estimate the allowable costs for deduction from the royalty amount of all the amalgamating parties.

For the amalgamator, the actual CERR for the year of amalgamation will be determined by including all the amalgamator's volumes for the year, as well as the volumes of all amalgamating parties after the amalgamation date.

For a member of the consortium (excluding the amalgamator), the actual CERR for the year of amalgamation will be a weighted average CERR based on an individual rate calculated before amalgamation and the amalgamator's rate.

13.1.4.2 CERR for the Post-Amalgamation Years

For all the amalgamating parties, the CERR estimate for the year following the amalgamation will be determined by including all the volumes for each member of the consortium for the amalgamation year. This CERR will be the basis of determining the following year's allowable estimated costs for the amalgamated clients.

The actual CERRs for the years after amalgamation for all the amalgamating parties will be determined by including all the volumes for each member of the consortium for the year. These CERRs will become the estimates for the following years.

13.2 Invoice Consolidations

The royalty clients wishing to consolidate their invoices, must submit their request in writing to the Team Leader, Client Services Help Desk, within one month of the effective billing period's invoice issue date. For example, if the effective billing period for consolidation is December 1997 then the Department must receive the request by the end of January 1998. Invoice consolidations have a direct impact on invoice charges, payments, deposits, Corporate Effective Royalty Rates (CERR), Allowable Cost Restrictions (ACR) and Annual Allowable Cost Restrictions (AACR).

The request to consolidate must be accompanied by an Invoice Consolidation Concurrence Form (ICCI). All parties involved in the invoice consolidation must sign this form. The ICCI Form is provided in Appendix P. The royalty clients must identify which client will become the **royalty payer**[*] for the consolidated entity. This client will be known as the supra client or the consolidator. The supra client must be a valid royalty client on the Department's registry. All charges related to the consolidated companies will appear on the supra client's invoice.

13.2.1 Reporting

All Industry reporting must remain at a royalty client level. The Department will continue calculating royalty at the royalty client level (except CERR, ACR and AACR). For consolidation purposes, royalty client reporting is rolled up to the supra client level.

13.2.2 Valuation

If the gas valuation structure of the royalty clients consists of both CAP and Reference Price, the gas valuation of the consolidating parties will revert to the Reference Price effective the first month of the year following consolidation. *(Refer to Section 6.5.2).*

If the gas valuation structure of the royalty clients consists of only CAP, the gas valuation of the consolidating parties shall remain CAP as long as their eligibility is maintained. *(Refer to Section 6.5.3).*

13.2.3 VA2, VA3 and VA4 Forms

The supra client for the consolidated entity is responsible for submitting VA2, VA3 and VA4 forms for all consolidated companies. To do this, they must compile all information for the affected companies and place the combined totals on a VA2/VA3/VA4 form. The VA2/VA3 totals apply for the whole year of consolidation, regardless of which month the consolidation took place. The calculated annual Gas Corporate Average Price (CAP) and monthly/annual Sulphur Valuation Price (Sulphur Corporate Average Price (S-CAP) or Sulphur Default Price) will be the same for all companies within the consortium. If the gas valuation structure for all the consolidating parties consists of CAP, the calculated Corporate Gas Factor (CGF) will be the same for all companies within the consortium.

Only one VA2, VA3 and VA4 form is required, including any amended forms, under the name and ID of the supra client for the consolidated entity.

13.2.4 Allowable Costs

After the consolidation date, all companies in the consortium may continue to report and receive allowable costs. The consolidation affects the Corporate Effective Royalty Rate (CERR) calculation.

13.2.4.1 CERR for the Consolidation Year

From the consolidation date to the end of the year, the supra client's CERR will be used to estimate the allowable costs for deduction from the royalty amount of all the consolidating parties.

If the supra client does not have a CERR, the Provincial Average CERR for the year of amalgamation will be used to estimate the allowable costs for deduction from the royalty amount of all the consolidating parties.

For the supra client, the actual CERR for the year of consolidation will be determined by including all the supra client's volumes for the year as well as the volumes of all consolidating parties after the consolidation date.

For a member of the consortium (excluding the supra client), the actual CERR for the year of consolidation will be a weighted average CERR based on an individual rate calculated before consolidation and the supra client's rate.

13.2.4.2 CERR for the Post-Consolidation Years

For all the consolidating parties, the CERR estimate for the year following the consolidation will be determined by including all the volumes for each member of the consortium for the consolidating year. This CERR will be the basis of determining the following year's allowable estimated costs for the consolidated clients.

The actual CERRs for the years after consolidation for all the consolidating parties will be determined by including all the volumes for each member of the consortium for the year. These CERRs will become the estimates for the following years.

13.2.5 Consolidation Termination

A request for terminating an invoice consolidation cannot be granted once the invoice has been consolidated for a billing period. Royalty clients wishing to terminate their invoice consolidation must submit their request to the Team Leader, Client Services Help Desk within one month of the effective billing period's invoice issue date. For example, if the effective billing period for de-consolidation is December 1997, then the Department must receive the request by the end of January 1998.

14. Valuing Raw Gas, Residue Gas and Ethane (Pricing Calculation)

14.1 Calculation of the Gas Reference Price

The Gas Reference Price for a month is calculated as:

Weighted Average Price of Alberta Gas for the month
...minus...
Transportation Cost Allowance for the month
...minus...
VPA* and **Aggregator*** OMAC charges adjustment for the month
...minus...
Pipeline Fuel/Loss Allowance* for the month
...plus or minus...
Adjustment for Prior Period Amendments for the month

Procedures for reporting and calculating the Gas Reference Price are described in the *"Ministry Natural Gas Reporting Guide". (Refer to Appendix D.)*

S.6(1) The Department will publish the production month's Gas Reference Price in an *Information Letter* on the 15th day of the second month following the production month, *unless* the 15th day is a weekend or a holiday; in which case, the next business day will apply.

The Gas Reference Price that is established for a month will not be changed retroactively.

S.27 The calculation of the Gas Reference Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

For definition, please refer to Appendix N - Glossary

14.1.1 Weighted Average Price of Alberta Gas

The weighted average price of Alberta gas for a month is calculated as:

(Value of gas consumed in Alberta in the month
...plus...
Value of gas exported from Alberta in the month)
...divided by...
(Gas consumed in Alberta *[GJ] ...plus...* gas exported from Alberta *[GJ]* in the month)

The **value of gas consumed in Alberta** is calculated in three steps using information reported by **large volume end-users*** (LVE) and **designated distributors*** (DD), including buy/sell end-users of the designated distributors. For purposes of this calculation, transactions are separated into "non-associated" *(dispositions to persons not associated with the seller)* and **"associated"*** *(dispositions to persons associated with the seller)*.

STEP 1:

Value of LVE non-associated transactions in the month (as reported to the Ministry)
...plus...
Value of LVE associated transactions in the month (GJ *...multiplied by...* weighted average non-associated LVE inlet price)
...equals...
Value of LVE transactions for the month

STEP 2:

Value of DD non-associated transactions in the month (as reported to the Ministry)
...plus...
Value of DD associated transactions in the month (GJ *...multiplied by...* weighted average non-associated DD inlet price)
...equals...
Value of DD transactions for the month

STEP 3:

Value of LVE transactions in the month
...plus...
Value of DD transactions in the month
...equals...
Value of gas consumed in Alberta for the month

For definition, please refer to Appendix N - Glossary

The **value of gas exported from Alberta** is also calculated in three steps, using information reported by the owner of the gas at the **point of removal***. Reporting is based on four designated removal points: Coleman, Empress, James/McNeill and "Other". *("Other" includes transactions from all export points other than the three specified locations.)* Transactions are separated into "non-associated" and "associated" in the same manner as for gas consumed in Alberta.

Effective January 1996, transactions of **ex-Alberta gas LDCs*** are separated from each removal point into a fifth ex-Alberta pool. The total net effects on royalty of applying this change to the January 1994 to December 1995 period were included as one-time special adjustments to the Gas Reference in the nine production months ending March 1997.

(Refer to Appendix D for more details on the calculation of Gas Reference Price.)

STEP 1:

Value of non-associated exports at the removal point in the month (GJ ...*multiplied by*... price
at the Alberta border, for each owner) for all owners at the removal point
...***divided by***...
Total non-associated exports at the removal point in the month (GJ) for all owners
...***equals***...
weighted average price at the removal point for the month

STEP 2:

(Non-associated exports at the removal point in the month (GJ) for all owners
...***plus***...
Associated exports at the removal point in the month (GJ) for all owners)
...***multiplied by***...
Weighted average price at the removal point for the month
...***equals***...
Value of gas exported at the removal point for the month

STEP 3:

Value of gas exported at each removal point, summed for all removal points
...***equals***...
Value of gas exported from Alberta in the month (excess **demand charges*** included)

NOTE: IF THE NON-ASSOCIATED DISPOSITIONS AT A REMOVAL POINT IN A MONTH ARE LESS THAN 50% (BY QUANTITY) OF THE GAS EXPORTED AT THE REMOVAL POINT, THEY WILL BE VALUED USING THE WEIGHTED AVERAGE PRICE OF EXPORTS AT ALL REMOVAL POINTS (1994 - 1995).

FOR 1996 AND FUTURE YEARS, ASSOCIATED DISPOSITIONS OF A REMOVAL POINT WILL BE VALUED UP TO THE NON-ASSOCIATED DISPOSITIONS OFTHE REMOVAL POINT. THE EXCESS OF ASSOCIATED DISPOSITIONS TO NON-ASSOCIATED DISPOSITIONS IS EXCLUDED FROM THE VALUE OF GAS EXPORTED FROM ALBERTA. THE QUANTITIES ARE SUBSEQUENTLY VALUED AT THE GAS REFERENCE PRICE.

For definition, please refer to Appendix N - Glossary

THAT WEIGHTED AVERAGE PRICE IS CALCULATED AS:

> ([Value of associated and non-associated gas exported at all other removal points] *...plus...* [value of non-associated gas exported at the removal point in question])
> ***...divided by...***
> ([Quantity (GJ) of associated and non-associated gas exported at all other removal points] *...plus...* [quantity (GJ) of non-associated gas exported at the removal point in question])

14.1.2 Transportation Cost Allowance

The **intra-Alberta transportation*** cost allowance for a month is calculated as:

> **Nova cost of service*** for the month
> ***...divided by...***
> **Nova net billable receipts*** (GJ) for the month

14.1.3 Valuation Point Adjustment* (VPA) and Aggregator Overhead Marketing and Administration Charges (OMAC) Adjustment

The VPA and Aggregator Adjustments are deductions in the calculation of the monthly reference price based on the following principles:

- The **Aggregator OMAC Adjustment*** rate is determined by the Department each month as a **proxy*** for the overhead, marketing and administration charges of **recognized aggregators***. The rate will be the weighted average OMAC type deduction of the designated large aggregators multiplied by the total percentage that the recognized aggregators volumes were of the total gas dispositions (for 1994 only), and the total gas removals from Alberta (for 1995 and onwards) in the previous year.
- The Department calculates the VPA as the average difference between purchases and sales prices obtained for companies identified as marketers. This is multiplied by the percentage that marketers were of the total gas dispositions (for 1994 only) and the total gas removals from Alberta (for 1995 and onwards), in the previous year. (For 1994 only, volumes purchased by marketers are net of the purchased portion of net injection calculated using the latest year for which that data is available.) For 1994, the average difference is deemed to be 10¢/GJ. The Department will calculate future average differences based on surveys of marketers.

****For definition, please refer to Appendix N - Glossary***

14.1.4 Pipeline Fuel/Loss Allowance

The pipeline fuel/loss allowance for a month is calculated as:

(Weighted Average Price of Alberta Gas *...minus...* Transportation Cost Allowance *...minus...* VPA and Aggregator OMAC Charges Adjustment) for the month
...multiplied by...
(1.0 *...minus...* [Nova net billable receipts *...divided by...* **Nova gross billable receipts***]) for the month

14.1.5 Adjustment for Prior Period Amendments

If the Ministry receives amendments to previous period reporting from companies upon whom it depends for the information used in calculating Gas Reference Price, the Ministry will calculate an adjustment to the current month's Gas Reference Price. The adjustment is calculated in the manner described in *Appendix D*. The maximum adjustment for any current month's Reference Price is an amount equal to 2% of the Gas Reference Price before amendments are considered. Any amount that is over the 2% limit is carried forward to the next succeeding Reference Price month. Amendments that are reported and included as adjustments in this manner are those which result from reporting errors or omissions by the reporting company.

If the adjustments result from re-determinations or re-allocations by a Facility Operator, pipeline company, producer or customer, the reporting company includes these adjustments in its reports for the delivery month in which they are transacted, and not for the production month to which the adjustments apply.

**For definition, please refer to Appendix N - Glossary*

14.2 Calculation of the Grandfathered Price

The Department will invoice the monthly Crown royalty share of **grandfathered contracts** using the Gas Reference Price. A final accounting and corporate royalty account adjustment to reflect the grandfathered price will be made annually

The Department will adjust the Crown royalty share of grandfathered contracts as follows:

Monthly Crown Royalty Quantity in GJ
...multiplied by...
(Monthly Gas Reference Price *...minus...* monthly Netback Selling Price)

The Department will honour dedicated reserves specified in a qualifying contract and identified in the application. The Crown interest and vintage of dedicated reserves is obtained from the stream ID. Where there is no **reserve dedication***, or the royalty client fails to identify the reserve dedication in its application, deliveries under a contract are deemed to be supplied at the royalty client's weighted average Crown interest and vintage calculated monthly as a composite factor which is the product of:

Royalty client's total Crown Royalty Share (in GJ) of raw gas, residue gas and ethane for the production month
...divided by...
Royalty client's total Alberta production (in GJ) of raw gas, residue gas and ethane for the production month

14.3 Calculation of the Gas Corporate Average Price

A royalty client who has a valid CAP election must determine and report its CAP annually by April 15 of the year following the year of production *(Refer to Section 22.2).*

Sch.1 - S.6(2) A royalty client's CAP for a year is calculated as follows:

(Value of sales to non-associates at the plant gate netback value
...plus...
Value of sales to associates valued at the associate's CAP, netted back to the plant gate
...plus...
Value of sales to associates where a CAP cannot be determined, valued at the Gas Reference Price for the month in which the transaction occurs
...plus...
Proprietary consumption* and other "fair-value[(1)] transactions" valued at the Gas Reference Price in effect for the month in which the transaction is made)
...divided by...
Total GJs of raw gas, residue gas and ethane included in the above transactions

Raw gas sales are included at actual netback value. Raw gas used as off-site fuel (which otherwise would require processing) or transferred to out of province gas plants for processing only (deemed as raw gas sales) are included in the royalty client's CAP calculation at 80% of the CAP price. Ethane sales are included at actual netback value. (This does not include light ends.)

(1) "Fair-value" transactions includes **swaps*** and **exchanges***.

NOTE: IF RAW GAS IS USED AS OFF-SITE FUEL OR IS DELIVERED TO AN OUT-OF-PROVINCE FACILITY FOR PROCESSING, THIS WILL BE CONSIDERED AS DEEMED RAW GAS SALES AND UOCR WILL NOT BE ALLOWED AS A DEDUCTION IN CALCULATING CROWN ROYALTY.

**For definition, please refer to Appendix N - Glossary*

14.3.1 Plant Gate Netback Value

The plant gate netback value for sales to non-associates is the sum of:

Value of sales transactions to non-associates
...minus...
Intra-Alberta transportation costs incurred on the subject transactions (including demand and **reservation charges*** on pipelines in existence on December 31, 1993)
...minus...
Ext-Alberta transportation costs incurred on the subject transactions (including demand and reservation charges on pipelines in existence on December 31, 1993) net of any revenue from **brokered transportation capacity***

Transportation costs do not include costs for a sales line connecting the plant to a pipeline.

Sales to recognized aggregators are included in the **netback price*** plus the unit cost of intra-Alberta storage (aggregators must disclose the storage charge on invoices to suppliers). For the designated large aggregators, the actual amount of the OMAC-type charges may be deducted. For other recognized aggregators, the weighted average of OMAC-type charges for the large aggregators may be deducted. The Department will publish the weighted average of OMAC-type charges annually for the large aggregators.

Proceeds from hedging transactions are not included in the CAP calculation. Brokered volumes are included at the actual sales value, and costs for brokered volumes cannot be deducted.

14.3.2 Sales to Associates Valued at the Associate's CAP

Where sales to an Associate are valued at the Associate's CAP, and that Associate is a United States-based corporation or ext-Alberta (within Canada) based corporation, the Associate's CAP is calculated as:

(Value of sales from Associate's total North American arm's-length sales
...minus...
Transportation costs incurred on these sales)
...divided by...
Total GJs included in the same sales transactions

The total plant gate netback value for sales to this type of Associate is calculated as:

(Total GJs sold to the Associate *...multiplied by...* Associate's CAP)
...minus...
Intra-Alberta transportation costs incurred on the sales, where the costs are not included in the Associate's CAP calculation
...minus...
Ext-Alberta transportation costs incurred on the sales, where the costs are not included in the Associate's CAP calculation

Where sales to an Associate are valued at the Associate's CAP, and that Associate is an Alberta-based corporation, the Associate's CAP is calculated in the same manner as the CAP of the royalty client.

**For definition, please refer to Appendix N - Glossary*

14.3.3 Minimum Price for the Gas Corporate Average Price

Sch. 1 - S.6(3)

The Department calculates the annual weighted average of Gas Reference Prices as:

> *The sum of* values (monthly Gas Reference Price *…multiplied by…* [intra-Alberta consumption
> *…Plus…* ext-Alberta deliveries, in GJ]) for each production month in the year
> ***…divided by…***
> *The sum of* volumes (intra-Alberta consumption *…plus….* ext-Alberta deliveries, in GJ) for all
> production months in the year

Price and quantity (GJ) data are taken from the information collected by the Ministry for the monthly Gas Reference Price calculation.

The Department will publish the annual weighted average of Gas Reference Prices in a Mineral Operations Information Bulletin on or before March 1 of the year following production to which the prices relate.

14.3.4 Correcting the CAP for Adjustments to Sales Proceeds or Costs

Where a royalty client receives adjustments to either the sale proceeds or costs relating to transactions that are included in the CAP calculation of a previous year, treatment of the adjustments will vary according to the circumstances of the case.

If:

- the recalculated CAP, including all adjustments for which the CAP has not previously been changed, is greater or less than the unadjusted CAP by an amount equal to or greater than 5% of the unadjusted CAP; *or*
- the royalty client has subsequently elected to use the Gas Reference Price in a year following the year to which the adjustment relates;

Then:

- the royalty client must file a recalculated CAP for the adjusted year with the Department; *and*
- the Department will re-calculate and invoice a Crown royalty adjustment to the royalty client; ***unless***
- the unadjusted CAP is less than 90% of the weighted average of Gas Reference Prices for the year and the recalculated CAP is also less than 90%, in which case the Department will not invoice a Crown royalty adjustment.

If:

- the recalculated CAP is within 5% of the unadjusted CAP,

Then:

- the royalty client must include the adjustments in the CAP calculation for the year in which the adjustments are received; ***unless***
- the royalty client requests that the Minister adjust his CAP and recalculate Crown royalty for the year to which the adjustment relates and the Minister approves the request, in which case the recalculation will be made.

14.4 Monthly Gas Corporate Average Price Estimate

14.4.1 Calculation of the Monthly CAP Estimate

The CAP is calculated annually by each royalty client with a valid CAP election.

The Department values and invoices each CAP royalty client's monthly raw gas, residue gas and ethane Crown royalty share using an estimated CAP that is:

> Gas Reference Price for the month
> ***…multiplied by…***
> the royalty client's **Corporate Gas Factor*** for the year

A royalty client's Corporate Gas Factor for a year is calculated as:

> the royalty client's CAP for the previous year
> ***…divided by…***
> the weighted average of Gas Reference Prices for the same year
> ***…subject to…***
> a minimum Corporate Gas Factor of 0.9

The Department calculates the Corporate Gas Factor and reports it to each royalty client who has a valid CAP election each year. For the implementation year, the Corporate Gas Factors will be calculated as:

> royalty client's weighted average unit value for 1993, based on the royalty client's reports to the Department (in place of the royalty client's CAP for 1993)
> ***…divided by…***
> weighted average unit value for the industry in 1993, based on all royalty client reports to the Department (in place of the weighted average of Gas Reference Prices for 1993)
> ***…subject to…***
> a minimum Corporate Gas Factor of 0.9

If a person becomes a royalty client after December 31, 1993, and has a valid CAP election, the Department will set that royalty client's Corporate Gas Factor for the first year at 1.0. Effectively, the Department will value and invoice that royalty client's monthly raw gas, residue gas and ethane Crown royalty share in its first year as a royalty client using the Gas Reference Price. After the first year, the CAP client's valuation price will be calculated as described above. *For further information, refer to Section 6.5.*

****For definition, please refer to Appendix N - Glossary***

15. Valuing Propane and Butanes

15.1 Valuing Crown Share of Propane and Butanes

15.1.1 Valuation Criteria

The net unit price at which the Department will value and invoice the monthly Crown royalty share of propane and butanes is:

Propane/Butanes Reference Price *(subject to a Floor Price*)*
...minus...
Transportation *(by region)* and Storage Allowances
...minus...
Fractionation Allowance**(for propane/butanes, contained in an NGL mix)*

15.1.2 Propane and Butanes Reference Prices

The Department calculates Propane and Butanes Reference Prices as the weighted average of prices paid that are representative of an Edmonton price for specification product. For the January 1994 to December 1999 period, average prices are calculated from information submitted for purchases of propane and butanes in the field that are based on an Edmonton price. For January 2000 forward, prices are calculated from information submitted for non-field purchases in the Edmonton area (refer to the description of the Edmonton Area on page 20 of Section 27).

The monthly Propane Reference Price and Butanes Reference Price are calculated as follows:

total value of propane/butanes purchase transactions reported in the month
that represent an Edmonton price
...divided by...
total volumes reported for the same purchase transactions

Major purchasers of propane and butanes, designated by the Minister, provide price and volume information each month by the 10th day of the second month following the production month to which they apply. If the 10th day falls on a weekend or a holiday, the next business day will apply. The NGL1 is required for the January 1994 to December 1999 period, while the NGL-100 is required for January 2000 and future production months. For reporting instructions, refer to Section 23 for the NGL1 and Section 27 for the NGL-100.

If the Department receives amendments to information filed by designated purchasers, for a previous period, the Department will:

- include the adjustments in calculating the Propane Reference Price and/or the Butanes Reference Price for the month in which the amendments are received, up to a maximum of 2% (10% for January 1998 forward) of the respective Reference Price calculated before the adjustments are applied; *and*
- carry forward any amounts above the maximum to the following month(s).

Amendments that are reported and included as adjustments in this manner are those which result from reporting errors or omissions by the reporting company.

**For definition, please refer to Appendix N – Glossary*

If the adjustments result from re-determinations or re-allocations by a Facility Operator, pipeline company, producer or customer, the reporting company includes these adjustments in its reports for the delivery month in which they are transacted, and not for the production month to which the adjustments apply.

If the information required to calculate either the Propane Reference Price or the Butanes Reference Price, or both, is not received by the prescribed date, the Minister will determine the Reference Price(s).

The Department will publish the Propane Reference Price and the Butanes Reference Price in an *Information Letter* on the 15th day of the second month following the production month to which the Reference Price applies. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

The Propane Reference Price and Butanes Reference Price that are established for a month will not be changed retroactively. The calculation of the Propane Reference Price and the Butanes Reference Price are subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

15.1.3 Propane and Butanes Floor Prices

The Department calculates Floor Prices for propane and butanes to protect the Crown against inappropriately depressed prices in the Edmonton market. In any month where the Floor Price of either propane or butanes exceeds the Reference Price for the same product, and the Minister determines that there is no valid market reason for the disparity, the Reference Price(s) will be the same as the Floor Price(s). *(Refer to Appendix E.)*

The Propane Floor Price is calculated from prices posted for specification propane at Conway, Kansas, netted back to Edmonton by deducting transportation and storage costs (using tariffs based on regular rates for four months and incentive rates for eight months each year). The Propane Floor Price is 90% of the price netted back from Conway.

The Butanes Floor Price is calculated from prices posted for normal butanes and iso-butanes at Conway, Kansas *(using a ratio of 65% normal butanes and 35% iso-butanes)*. This is netted back in the same manner as for propane. The Butanes Floor Price is 90% of the price netted back from Conway.

The Department will publish the Propane Floor Price and the Butanes Floor Price in an *Information Letter* on the 15th day of the second month following the production month to which the floor prices apply. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

If either a Propane Floor Price or a Butanes Floor Price becomes a Reference Price, that Floor Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

15.2 Valuing Crown Share Pentanes Plus

15.2.1 Valuation Criteria

The net unit price at which the Department will value and invoice the monthly Crown royalty liability for pentanes plus is:

Pentanes Reference Price ***...minus...*** Transportation *(by region)* and Storage Allowances (for pentanes plus Contained in an NGL mix ***...minus...*** Fractionation Allowance *(for pentanes plus contained in an NGL mix)*

15.2.2 Pentanes Reference Price

Calculation for January 1994 to December 1999 Production Months

S.6(5)
Sch.2 - S.2(1)

The Pentanes Reference Price is the simple average of daily posted purchase prices at Edmonton for 40-degree crude oil and specification pentanes plus, obtained from publicly available sources. The Department calculates the Pentanes Reference Price as:

the sum of all individual prices posted in the month ***...divided by...*** the number of postings in the same month

The Department will publish the Pentanes Reference Price in an *Information Letter* on the 15th day of the second month following the production month to which the Reference Price applies. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

The Pentanes Reference Price that is established for a month will not be changed retroactively. The calculation of the Pentanes Reference Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

Calculation for January 2000 and Future Production Months

The Department calculates the Pentanes Reference Price as the weighted average of prices paid for pentanes specification product purchased at non-field locations in the Edmonton Area (Refer to Edmonton Area description on page 20 of Section 27). Major purchasers of pentanes plus, as designated by the Minister, provide price and volume information on the NGL-100 form each month by the 10th day of the second month following the production month to which they apply. If the 10th day falls on a weekend or a holiday, the next business day will apply. Refer to Section 27 for reporting instructions on the NGL-100.

The monthly Pentanes Reference Price is calculated as follows:

total value of pentanes purchased in the Edmonton Area as reported in the month ***...divided by...*** total volumes reported for the same purchase transactions

If the Department receives amendments to NGL-100 information filed by designated purchasers, for a previous period, the Department will:

- include the adjustments in calculating the Pentanes Reference for the month in which the amendments are received, up to a maximum of 10% of the respective Reference Price calculated before the adjustments are applied; *and*
- carry forward any amounts above 10% to the following month(s).

Amendments that are reported and included as adjustments in this manner are those which result from reporting errors or omissions by the reporting company.

If a business adjustment results from re-determinations or re-allocations by a Facility Operator, pipeline company, producer or customer, the reporting company includes these adjustments in its reports for the delivery month in which they are transacted, and not for the production month to which the adjustments apply.

If the information required to calculate the Pentanes Reference Price is not received by the prescribed date, the Minister will determine the Reference Price(s).

The Department will publish the Pentanes Reference Price in an *Information Letter* on the 15th day of the second month following the production month to which the Reference Price applies. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

The Pentanes Reference Price that is established for a month will not be changed retroactively. The calculation of the Pentanes Reference Price is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

15.3 Allowances Deducted from Propane, Butanes and Pentanes Reference Prices

15.3.1 Regional Transportation Allowances

Sch.2 - S.2(2)(a)

The Department deducts a Transportation Allowance from the Propane Reference Price, the Butanes Reference Price and the Pentanes Reference Price as part of its calculation of the price at which it will value the Crown royalty share of each of those products.

The Transportation Allowance represents the difference between the price at Edmonton and the plant gate price, excluding the fractionation allowance and any storage or other fees.

Transportation Allowances are calculated for each of the four regions during the month *(refer to Appendix F)*. This is done for:

- specification propane/butanes (Spec Product);
- specification pentanes plus (Spec Pentanes); *and*
- product transported as a component of an NGL mix (NGL mix).

Transportation Allowances are calculated using information reported by designated major purchasers of propane, butanes or pentanes plus. Information is reported monthly by the 10th day of the second month following the production month to which they apply. If the 10th day falls on a weekend or a holiday, then the next business day will apply.

Calculation for January 1994 to December 1999 Production Months

Transportation Allowances are calculated from the cost information reported on the NGL1 form.

Calculation for January 2000 and Future Production Months

Transportation Allowances are calculated from the purchase information reported by designated major purchasers on the NGL-100 form. Transportation Allowances are determined by calculating the differences for each product between average reported field purchase prices and average reported Edmonton non-field purchase prices. A fractionation allowance is also deducted in the calculation of Transportation Allowances for NGLs in a mix.

Transportation Allowances for a month are calculated as follows:

Specification Propane/Butanes = weighted average of specification propane and butanes transportation differentials in each region.

Specification Pentanes Plus = specification pentanes transportation differential in each region.

Pentanes Plus, Propane and Butanes in an NGL mix = weighted average of NGL mix differentials for pentanes, propane and butanes in each region, then subtracting fractionation allowance.

Transportation Differentials for each product are calculated by subtracting the weighted average field purchases prices reported on the NGL-100 form, from the average reported Edmonton non-field purchase prices.

If the Department receives amendments to information filed by designated purchasers, for a previous period, the Department will:

- include the adjustments in calculating the Transportation Allowances for the month in which the amendments are received, up to a maximum of a 100% of gross product prices (except no maximum for January 1994 to April 1996 and a maximum of 20% of gross product prices for May and June 1996; *and*
- carry forward any amounts above the maximum to the following month(s).

Amendments that are reported and included as adjustments in this manner are those which result from reporting errors or omissions by the reporting company.

If a business adjustment results from re-determinations or re-allocations by a Facility Operator, pipeline company, producer or customer, the reporting company includes these adjustments in its reports for the delivery month in which they are transacted, and not for the production month to which the adjustments apply.

The Department will publish the regional Transportation Allowances in an *Information Letter* by the 15th day of the second month following the production month to which the allowances apply. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

Transportation Allowances that are established for a month will not be changed retroactively. The calculation of the Transportation Allowances is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

Transportation Allowance Estimates

January 1994 to December 1999 production months

- If there is no information available to calculate a Transportation Allowance, the Department will determine the Transportation Allowance as the simple average of the other regional Transportation Allowances within that category (before amendment effects).

January 2000 and future production months

- All transportation allowances except specification pentanes - If there is no information available to calculate a Transportation Allowance, the Department will determine the Transportation Allowance as the weighted average of the other regional Transportation Allowances within that category (before amendment effects). The weighting uses provincial production in each region, for each category, from the previous calendar year.
- Specification Pentanes – If there is no information available to calculate a Transportation Allowance for specification pentanes, or if the information has been submitted by a single reporting company, the Department will determine the Transportation Allowance as the simple average of the preceding twelve months for that region (before amendment effects). The preceding period cannot extend past January 2000. A continuing situation of two months or more would require a revisit of the business rule.

15.3.2 Storage Allowance

NOTE: THIS SECTION APPLIES ONLY FOR THE PRODUCTION YEAR 1994. THE STORAGE ALLOWANCE FOR PRODUCTION YEAR 1995 ONWARDS IS SET AT $0 PER m^3. THE NGL2 FORM IS NOT REQUIRED FOR 1995 ONWARDS.

Sch.2 - S.2(2)(b) The Department deducts a Storage Allowance from the Propane Reference Price, the Butanes Reference Price and the Pentanes Reference Price as part of its calculation of the price at which it will value the Crown royalty share of each of those products (including raw product storage). There is no storage allowance for specification pentanes plus, but there is for specification propane and butanes.

The Storage Allowance is a portion of the average Alberta storage cost. The average Alberta storage cost is the previous year's average fee per unit charged at Fort Saskatchewan to store propane, butanes and pentanes plus *(natural gas liquids* [for definition, please refer to Appendix N – Glossary]),* as reported on the NGL2 form by the operators of designated storage facilities. The portion that is deductible as a Storage Allowance is the annual ratio of intra-Alberta natural gas liquid dispositions to total Alberta produced natural gas liquids.

The Storage Allowance is calculated annually and is applied to propane, butanes and pentanes plus (contained in an NGL mix) valuations for each month in the year.

The Department calculates the annual Storage Allowance *(dollar per cubic metre)* as follows:

- calculate the weighted average unit cost of storage for natural gas liquids:

total storage costs
...divided by...
total volumes stored

NOTE: FOR THE PURPOSE OF THIS SECTION, TOTAL VOLUMES STORED IS DEFINED AS TOTAL INLET VOLUMES. TOTAL STORAGE COST IS DEFINED AS TOTAL FEES FOR THE TOTAL INLET VOLUMES (EXCLUDING COST OF SERVICE).

- calculate the intra-Alberta natural gas liquids disposition factor:

[(volumes produced in Alberta) ...minus...(volumes removed from Alberta)]
...divided by...
volumes produced in Alberta

- calculate the Storage Allowance:

weighted average cost per unit of natural gas liquids storage
...multiplied by...
intra-Alberta natural gas liquids disposition factor

If the Ministry receives amendments to prior period reporting by companies upon whom it depends for information used in calculating the Storage Allowance, the Ministry will calculate an adjustment to the current year Storage Allowance. These amendments are those which result from reporting errors or omissions by the reporting company.

If adjustments result from re-determinations or re-allocations by a Facility Operator, pipeline company, producer or customer, the reporting company includes these adjustments in its reports for the delivery year in which they are transacted.

The Department will publish the annual Storage Allowance in an *Information Letter* on or before March 25 of the year to which the allowance applies.

The annual Storage Allowances that are established for a year will not be changed retroactively. The calculation of the annual Storage Allowance is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

15.3.3 Fractionation Allowance

Sch.2 - S.2(2)(c) The Department deducts a Fractionation Allowance from the Propane Reference Price, the Butanes Reference Price and the Pentanes Reference Price as part of its calculation of the price at which it will value the Crown royalty share of propane, butanes and pentanes plus, which are produced as a component of an NGL mix.

The Fractionation Allowance is equal to the standard fee specified in the Ethane Plus System Trading Agreement (EPSTA), for as long as that fee represents industry average fractionation costs, and the scope of costs covered by the fee remains unchanged. If the **EPSTA fee** *(for definition, please refer to Appendix N – Glossary)* includes allowances for de-ethanization costs, then the de-ethanization costs will be allowed. The Fractionation Allowance will be changed only when there is a change to the EPSTA fee.

The Department will publish the Fractionation Allowance in an Information Letter by the 15th day of the second month following the production month to which a changed Fractionation Allowance applies. If the 15th day falls on a weekend or a holiday, then the next business day will apply.

The Fractionation Allowance that is established for a month will not be changed retroactively. The calculation of the Fractionation Allowance is subject to an independent audit conducted on behalf of the petroleum and natural gas industry.

15.3.4 Special Pentanes Processing Allowance

The Department deducts a Special Pentanes Processing Allowance from the Pentanes Reference Price as part of its calculation of the price at which it will value the Crown Royalty Share of pentanes plus. This allowance is provided on a case by case basis, if approved by the Minister, for specified streams of pentanes which are:

- produced in significant quantities;
- forced to be strictly segregated in transportation and processing;
- extremely sour in nature; and
- consistently valued at a price significantly less than the Pentanes Reference Price.

Royalty clients may request in writing to the Department for approval of Special Pentanes Processing Allowance.

The Department will publish the Special Pentanes Processing Allowances in an Information Letter by the 15th day of the second month following the production month to which the allowances apply. If the 15th day falls on a weekend or a holiday, the next business day will apply.

The Special Pentanes Processing Allowance that is established for a month will not be changed retroactively.

NOTE: THIS ALLOWANCE, AND THE QUALIFICATION OF THE STREAMS FOR THIS ALLOWANCE, WILL BE REVIEWED BY THE CROWN PERIODICALLY (PLEASE REFER TO APPENDIX N – GLOSSARY FOR DEFINITION OF SPECIAL PENTANES).

15.4 Valuing Sulphur

15.4.1 Monthly Reporting

Effective with production month January 1997, all royalty clients having annual sulphur production of 30,000 tonnes or more (based on previous year's production) must file VA4 forms monthly to determine their Sulphur Corporate Average Price (S-CAP). The form is filed on a "best efforts" basis, i.e., using the best information available at the time of filing. The Department will notify the royalty clients who are in this category. Subsequent amendments to VA4 forms need not be filed.

Those royalty clients whose annual sulphur production is less than 30,000 tonnes (based on previous year's production) may choose to file VA4 forms monthly and then, must continue to file for the entire year. *(Refer to Section 23.4).* The Department values and invoices the Crown royalty share of sulphur production monthly using the royalty client's S-CAP.

For royalty clients who are not required and, therefore, choose not to file VA4 forms, a Sulphur Default Price will be used to value the Crown royalty share of sulphur production monthly. A month's Sulphur Default Price is the weighted average unit value of all arms' length sales reported on the VA4 forms by royalty clients. The Sulphur Default Price is also used in valuing sulphur monthly for provisional assessment. *(Refer to Section 26.1.3).*

The VA4 forms must be filed on or before the 15th day of the second month following the production month to which the S-CAP applies. If the 15th day falls on a weekend or a holiday, the next business day will apply.

15.4.1.1 Monthly Sulphur Corporate Average Price Calculation

A royalty client's S-CAP for a month is calculated using the following for that month:

Net revenue at the plant gate from arms' length sales of Alberta gas-plant-produced sulphur
...divided by...
*Total tonnes of sulphur included in the above transactions
...subject to...
A minimum S-CAP of $0.00 (zero)

*Royalty clients must report their own volumes of plant-produced sulphur. This does not include other producer's share of sulphur, if royalty clients are also marketing other producer's share of sulphur.

If a royalty client's VA4 results in a negative unit value, the price used will be $0.00; and the royalty client will be allowed to carry forward and add the volumes and values to the following month's sales data to calculate that month's S-CAP.

The net revenue from sales of Alberta gas-plant-produced sulphur in a month is the:

value of sales of Alberta gas-plant-produced sulphur in the month
...minus...
transportation cost incurred in the month for sulphur
...minus...
costs incurred in the month for transportation-related storing, loading and handling of the sulphur (costs incurred in the month that are not eligible for "GCA" Allowable Costs)

15.4.1.2 Monthly Sulphur Default Price Calculation

The Department calculates monthly Sulphur Default Price from the VA4 forms submitted by royalty clients. The monthly Sulphur Default Price will be published in the *Information Bulletin* after it is determined.

The Department calculates the monthly Sulphur Default Price as:

the weighted average unit value of all arms'-length sales, as reported by royalty clients in their S-CAP filings to the Department for the month

NOTE: (1) ROYALTY CLIENTS WHOSE S-CAP FILINGS ARE BELOW THE MINIMUM S-CAP WILL HAVE THEIR NET MONTHLY REVENUE CONVERTED TO ZERO FOR THE DETERMINATION OF THE MONTHLY SULPHUR DEFAULT PRICE. ALL REPORTED TONNAGE WILL BE INCLUDED IN THE CALCULATION.

(2) THE SULPHUR DEFAULT PRICE THAT IS ESTABLISHED FOR A MONTH WILL NOT BE CHANGED RETROACTIVELY.

15.4.2 Annual Reporting

All royalty clients who have filed monthly VA4 forms must file annual VA3 forms. *(Refer to Section 23.3)*. The VA3 forms remain the primary valuation tool and the S-CAP determined therefrom will replace the entire year's monthly prices determined from the VA4 forms. This will create amendment transactions for all the months of the production year for which the royalty client filed VA4 forms.

Sch.3 - S.4 Royalty clients, who do not file VA4 forms because their sulphur production is less than 30,000 tonnes annually, may choose to file an annual VA3 form. If they so choose, the S-CAP determined from the VA3 filing will replace the Sulphur Default Price for all the months of the year.

The VA3 forms must be filed on or before April 15 of the year following the production year to which the VA3 form applies.

Sch.3 - S.5 The Department will calculate an annual Sulphur Default Price to value sulphur for those royalty clients who chose to have their monthly sulphur valued at the monthly Sulphur Default Price, and who chose not to file an annual VA3 form. For those royalty clients, the Department will replace the monthly Sulphur Default Price with an annual Sulphur Default Price, thereby creating amendment transactions for all the months of the production year which were subject to the monthly Sulphur Default Price.

If a royalty client's arms' length sales for a year is less than 10% of his total Alberta gas plant production for that year, the Department will value and invoice that royalty client's Crown royalty share of sulphur using the annual Sulphur Default Price.

Interest will be charged or paid on Crown royalty difference when adjusting the sulphur from monthly to annual valuation.

Unreconciled sulphur volumes will be reported and assessed to the Facility Operator monthly using the monthly Sulphur Default Price. There will be no adjustment to convert the valuation of unreconciled sulphur volumes from monthly to annual Sulphur Default Price.

16. Alberta's Royalty Share of Cost Allowances

16.1 Crown Share of Cost Allowances

16.1.1 Monthly Calculation

The Department deducts the Crown share of Cost Allowance each month as a reduction from the Crown royalty payable in that month. The monthly deduction is unique to each royalty client, and is calculated as:

(Unit Operating Cost Rate *…multiplied by…* energy adjusted gas equivalent volume of Crown royalty gas and gas products) for the Crown royalty share of the royalty client at each EUB facility in the month
…plus…
Crown Share of Capital Cost Allowance paid to the royalty client for the preceding year *…divided by…*12
…plus…
Crown Share of Custom Processing Cost Allowance paid to the royalty client for the preceding year *…divided by…* 12

For 1994, the implementation year, the estimated monthly Crown share of Capital Cost Allowances and Crown share of Custom Processing Cost Allowances (net of estimated Crown share of Operating Cost Allowances) will be calculated using 1993 information reported to the Department. For 1995 and onwards, the estimated monthly Crown share of Capital Cost Allowances will be based on the previous year's actual Capital Cost Allowance and Capital Cost Allowance Reallocation costs reported on the AC2 and AC3 forms respectively. The estimated monthly Crown share of Custom Processing Allowances will be based on the previous year's actual Custom Processing Fees paid reported on the AC5 form, net of allowed operating costs.

A person who becomes a royalty client after December 31, 1993, must request in writing to the Department for an estimated monthly Crown share of Capital Cost Allowances and Crown share of Custom Processing Cost Allowances for the first year of operation. The request must be received on or before the 15th day of the second month following the production month to which it applies. Sufficient information must be provided to support the requested estimate. If approved, the Department will use the submitted information in calculating the monthly Crown share of Capital Cost Allowances and Custom Processing Cost Allowances. The Department will not make retroactive adjustments if such requests are received late or they do not provide sufficient information for approval.

For new royalty clients, the Corporate Effective Royalty Rate (**CERR**)* will be the Provincial Average from the previous year. The Provincial Average CERR is determined once a year in June. This rate is published in the Department's *Mineral Operation's Information Bulletin. (Refer to Section 7 and Section 16.8.2.)*

For definition, please see Appendix N - Glossary.

16.2. Amending Monthly Crown Share of Cost Allowance Estimates

If a royalty client's business in a year changes sufficiently that the Crown share of Capital Cost Allowance, or Crown share of Custom Processing Cost Allowance from the preceding year is no longer relevant, the royalty client may request in writing to the Department for an adjustment to his monthly estimate. Sufficient information must be provided to support the requested change and, if approved, the Department will use the new information in its calculation of the monthly deduction on a prospective basis.

16.2.1 Annual Adjustment from Estimate to Actual

S.17(4) Annually, the Department will calculate:

- the difference between the estimated Crown share of Capital Cost Allowances deducted during the year and the actual Crown share of Capital Cost Allowances calculated for each royalty client, *and*
- the difference between the estimated Crown share of Custom Processing Cost Allowances deducted during the year and the actual Crown share of Custom Processing Cost Allowances calculated for each royalty client.

The Department does not charge or pay interest on the annual adjustment from estimate to actual costs. However, interest will be charged or paid on amendments to annual adjustments and on forms received subsequent to initial annual processing. Interest will be effective from an annual adjustment date.

The annual adjustment to a royalty client's corporate account will appear on the royalty client's invoice in June of the year following the production year to which the adjustment relates.

NOTE: FOR JANUARY, FEBRUARY AND MARCH PRODUCTION MONTHS, THE DEPARTMENT WILL USE PREVIOUS YEAR'S ESTIMATES OF CROWN SHARE OF CAPITAL COST ALLOWANCES, CUSTOM PROCESSING COST ALLOWANCES AND CERR. THESE ALLOWANCES WILL BE ADJUSTED IN APRIL'S BILLING PERIOD WHEN NEW ESTIMATES FOR THE CURRENT YEAR BECOME AVAILABLE. THESE NEW ESTIMATED ALLOWANCES WILL THEN BE USED FOR THE REMAINDER OF THE CURRENT YEAR.

16.3 Facility Cost Centre Accountability

A Facility Cost Centre (FCC) is a compressing, gathering or processing facility under the ownership of one or more royalty clients and under one operator.

A facility that is used in a function for which the cost is recognized through a deduction from the price paid for Crown royalty *(e.g., a **fractionation facility*****)* is not an eligible Facility Cost Centre.

Annual Capital Cost Allowances are calculated at a Facility Cost Centre level *(formerly known as a GCA Facility)*. The operator of each Facility Cost Centre *(FCC Operator)* is to account for the Capital Cost Allowances at that Facility Cost Centre, for Crown royalty purposes.

A FCC Operator is required to provide information to the Department:

- describing the compressing, gathering and processing facilities that are included in the Facility Cost Centre and the Facility Cost Centre's ownership interests *(refer to Section 24.1); and*
- describing the **allowable capital costs***, calculation of Capital Cost Allowances and allocation of Capital Cost Allowances to owners or designated royalty clients *(refer to Section 24.2)*.

For definition, please see Appendix N - Glossary.

The following forms should be submitted:

S.17(7) An AC1 form *(refer to Section 24.1)* describing the Facility Cost Centre ownership interests on December 31 of the production year must be received by the Client Services Help Desk on or before March 1 of the year following the production year to which it relates.

An AC1 form must also be submitted:

- to register a new Facility Cost Centre that commences operation after January 1, 1994;
- to register a change in the operator of a Facility Cost Centre;
- to register a change in the owners of the Facility Cost Centre;
- to terminate a Facility Cost Centre;
- to shut in a Facility Cost Centre;
- to reactivate a shut in Facility Cost Centre; and
- to register any other relevant changes.

NOTE: (1) IN RESPECT OF PRODUCTION YEAR 1994 ONLY, THE FCC OPERATORS ARE NOT REQUIRED TO COMPLETE PART 4 (FACILITY COST CENTRE OWNERSHIP) OF THE AC1 FORM.

(2) NO REPORT IS REQUIRED TO ESTABLISH A FACILITY COST CENTRE THAT IS REGISTERED WITH THE DEPARTMENT ON DECEMBER 31, 1993.

(3) OPERATORS OF FACILITY COST CENTRES THAT PROCESS ONLY FREEHOLD VOLUMES SHOULD REGISTER THESE FACILITIES WITH THE DEPARTMENT ON AC1 FORMS.

S.17(8) An AC2 form describing the allowable capital costs, calculation of Capital Cost Allowances and allocation of Capital Cost Allowances to owners or designated royalty clients must be received by the Client Services Help Desk on or before April 15 of the year following the production year to which the report relates. *(Refer to Section 24.2.)*

16.4 Annual Allowable Capital Costs

The allowable capital costs that may be included in the calculation of Capital Cost Allowances for a Facility Cost Centre are described in *Appendix G.*

Appendix G also includes a description of non-allowable capital costs and a schematic depicting the general definition of allowable and non-allowable capital costs.

The Minister may approve additions/deletions to the list of allowable costs or require additions/deletions to the list of non-allowable capital costs. Where such a change is approved/required, the Department:

- will announce the change in an *Information Letter; and*
- will include that change in the next update of the *Principles and Procedures* Manual.

The amount of allowable capital cost at a Facility Cost Centre for the beginning of the year is the **net book value*** of the allowable capital cost at the end of the previous year, as recorded in the Department's records.

****For definition, please see Appendix N - Glossary.***

The amount of allowable capital cost at the end of the year before depreciation at a Facility Cost Centre is:

allowable capital cost at the beginning of the year
*...**plus**...*
acquisition of new assets during the year at cost
*...**plus**...*
acquisition of previously **depreciated assets*** at net book value(1)
*...**plus**...*
assets returned to service at net book value(2)
*...**minus**...*
dispositions of assets at net book value(3)
*...**minus**...*
out-of-service assets* at net book value(4)
*...**minus**...*
retirements at net book value(5)

1. If *previously depreciated assets* (according to Department records) are acquired for processing new reserves, a FCC Operator may apply to the Department, and upon receiving approval may value those assets at other than net book value.
2. The net book value of a *retired or **terminated asset**** is zero.
3. If the net book value of a ***disposed asset**** is not identifiable, the asset may be removed at a net book value estimated by a professional engineer.
4. Out-of-service assets include assets that are shut in or abandoned. These assets may be removed from the facility capital pool after one full year (12 months) of out-of-service status. These assets can be reactivated when production commences to match revenues with costs. The reinstatement value will be the net book value of the asset at the time of shut in.
5. Any remaining, undepreciated allowable capital cost is added to the Capital Cost Allowance in the year in which the asset is retired or terminated.

16.5 Calculating Annual Capital Cost Allowance

The annual Capital Cost Allowance for a Facility Cost Centre is calculated as:

annual depreciation on allowable capital costs
*...**plus**...*
retired assets* at the net book value in the year
*...**plus**...*
return on average capital

Refer to *Section 24.2* for a description of the procedures related to reporting and determining Capital Cost Allowance.

The *annual depreciation on allowable capital costs* for a Facility Cost Centre is calculated as:

allowable capital costs at the end of the year before depreciation
*...**divided by**...*
remaining useful life*of the Facility Cost Centre (in years)

****For definition, please see Appendix N - Glossary.***

The *remaining useful life* of a Facility Cost Centre is determined based on the economic life of the reserves, which the Facility Cost Centre serves.

In the past, in cases where the useful life of a Facility Cost Centre was estimated to be less than 10 years, clients were required to file supporting documentation respecting the economic life of related gas reserves with the EUB for technical review. The department would then establish the depreciation period for purposes of Capital Cost Allowance (formerly Gas Cost Allowance).

Effective **January 1, 1996, (see next page for effective January 31, 1998)** subject to Department's review and approval, the following applies:

1) Clients will determine the number of years an asset will be used to compress, gather or process gas for the identified reserves tied to the Facility Cost Centre.

   - to **establish** the Total Useful Life for a **new Facility Cost Centre**
   - to **increase** the Remaining Useful Life for an **existing Facility Cost Centre**
   - to **reduce** the Remaining Useful Life for an **existing Facility Cost Centre.**

   This determination is to be based on the length of time the asset will provide service to the client in its respective function.

2) If a partially depreciated Facility Cost Centre is sold the remaining useful life of the Facility Cost Centre continues on the same basis as before the sale. The allowable capital for the new owner is the undepreciated balance at the time of purchase.

3) If a fully depreciated Facility Cost Centre is sold and new reserves are not tied to the facility, the remaining useful life of the Facility Cost Centre is zero.

4) If a fully depreciated Facility Cost Centre is sold at arms length and new reserves are tied to the facility, the buyer may determine the further useful life, establish it for the Facility Cost Centre and upon obtaining department approval, depreciate the asset at other than net book value.

The depreciation allowable, as a part of the Capital Cost Allowance deduction for royalty purposes, is the straight line depreciation (the allowed Facility Cost Centre capital divided by the number of years determined as the useful life of the Facility Cost Centre).

Clients do not need to file supporting data with an application for a Facility Cost Centre Setup/Change and approval by the EUB is no longer required. The documentation supporting each application must, however, be retained by the client and submitted for review at the Department's request.

A FCC Operator may request a change to the remaining useful life of a Facility Cost Centre by submitting an amended AC1 form to the Department on or before May 15 of the year following the production year to which the change applies. If the Department approves the request, the remaining useful life will be adjusted and the effective date of the change will be the first day of the production year to which the change applies. If the AC1 is received after the May 15 deadline, the effective date of the change will be the first day of the next production year. Changes to the remaining useful life of a Facility Cost Centre will not be retroactive.

Effective January 31, 1998, the Department has temporarily fixed the remaining useful life for all Facility Cost Centres, including shut-in facilities, at current levels. Revisions to a Facility Cost Centre's remaining useful life will be held in abeyance, with the undermentioned exceptions until it is rescinded.

During the period of the remaining useful life 'freeze', the following will apply effective from January 31, 1998:

- all existing remaining useful life elections will remain as current.
- the remaining useful life of a new Facility Cost Centre will be set at 10 years for processing, gathering and compressing Facility Cost Centres.

In those instances where the imposed 10 years or the existing election clearly do not apply to the remaining reserves, the Facility Cost Centre operator may submit a request to the Department with appropriate documentation, of a more appropriate remaining life for the Facility Cost Centre. The necessary documentation will, at a minimum include a "sign-off" as to estimated reserve life by a professional accredited engineer. Further, the request must address the operative depletion plan for the in-place reserves.

Should the remaining useful life (rate of depreciation) of a Facility Cost Centre be revised, such change will be effective as of the date the application is received in the Department.

Retroactive changes to the remaining useful life of a facility cost centre will not be made with the exception of facilities brought on stream in 1997 that are not as yet set-up in the Department's records. In these instances, where the proposed remaining useful life of the Facility Cost Centre is less than the above noted 10 years, the Facility Cost Centre Set-up/Change (AC1) form must be accompanied by an estimation of the in-place reserves and reference to the operative depletion plan. These estimates are to be 'signed-off' by a professional accredited engineer. The following should be noted:

- If a partially depreciated Facility Cost Centre is sold, the remaining useful life of the Facility Cost Centre continues on the same basis as before the sale. The Allowable Capital for the new owners is the undepreciated balance at the time of purchase.
- If a fully depreciated Facility Cost Centre is sold, and new reserves are not tied to the facility, the remaining useful life of the Facility Cost Centre remains zero.
- If a fully depreciated Facility Cost Centre is sold at arms' length, and new reserves are subsequently tied to the facility, the Department will set the remaining useful life of the Facility Cost Centre as though it were a new Facility Cost Centre i.e.: 10 years. The buyer may apply to the Department to depreciate the Facility Cost Centre at other than net book value. If the Department approves the request, the remaining useful life for the Facility Cost Centre will be effective from the date the application is received in the Department.

The *return on average capital* for a Facility Cost Centre is calculated as:

[([allowable capital cost at the beginning of the year *...plus...* allowable capital cost at the
end of the year after depreciation] *...divided by...* 2)
...plus...
original capital cost of the site *(land)* on which the Facility Cost Centre is located
...plus...
([spare parts inventory at the beginning of the year *...plus...* spare parts
inventory at the end of the year] *...divided by...* 2)
...multiplied by...
Rate of Return for the year

Represented by the following formula

WHERE:

$$\left[\frac{(ACCBY + ACCEY)}{2} + OCCL + \frac{(SPIBY + SPIEY)}{2}\right] \times RR$$

ACCBY = ALLOWABLE CAPITAL COST AT THE BEGINNING OF THE YEAR
ACCEY = ALLOWABLE CAPITAL COST AT THE END OF THE YEAR AFTER DEPRECIATION
OCCL = ORIGINAL CAPITAL COST OF THE SITE (LAND)
SPIBY = SPARE PARTS INVENTORY AT THE BEGINNING OF THE YEAR
SPIEY = SPARE PARTS INVENTORY AT THE END OF THE YEAR
RR = RATE OF RETURN FOR THE YEAR

The Minister has established the *Rate of Return* at 15% for 1994 and subsequent years.

The allowable capital cost at the end of the year after depreciation is calculated as:

Allowable capital cost at the end of the year before depreciation
...minus...
Depreciation

16.6 Custom Processing Adjustment to Capital Cost Allowance

The Capital Cost Allowance calculated as described in *Section 16.5* is reduced by a ***Custom Processing Adjustment Factor**** *(CPAF)* to eliminate the Capital Cost Allowances attributable to custom processing. The Department has calculated the custom processing adjustment factors and forwarded this information to the FCC Operator of each Facility Cost Centre which was in operation prior to 1993.

The *custom processing adjustment factor* for a Facility Cost Centre is calculated as:

(Facility custom processing throughput volumes for 1990, 1991 and 1992 *(pre-1994 GC5)*
...divided by...
Facility total throughput volumes for 1990, 1991 and 1992 *(pre-1994 GC4)*)
...multiplied by...
100

For Facility Cost Centres that become operational after 1992, the FCC Operator must indicate the custom processing adjustment factor for the initial production year when submitting an AC2 form. This form should be filed for each Facility Cost Centre with supporting details of the custom processed volumes by royalty client and of the total Facility Cost Centre's throughput volumes. The supporting details should be reported on the CPAF form *(Appendix P)*.

To determine the CPAF for Facility Cost Centres which became operational during the year, or to change an existing Facility Cost Centre's CPAF during the year, a written request with an accompanying CPAF form must be submitted showing how the factor was derived.

If a Facility Cost Centre does not have any **custom user*** volumes, the AC2 form must report the CPAF factor as 0%. This field must not be left blank; otherwise, the CPAF factor will *default* to 100%. A CPAF form need not be filed in this case.

For definition, please see Appendix N - Glossary.

A Facility Cost Centre that has one year or less of remaining useful life at January 1, 1994 only, will have a *custom processing adjustment factor* of zero.

The Capital Cost Allowance after the custom processing adjustment that may be allocated to royalty clients at a Facility Cost Centre is calculated as:

Capital Cost Allowance *(as calculated in Section 16.5)*
...multiplied by...
(100 *...minus...* Custom Processing Adjustment Factor)
...divided by...
100

The CPAF established or approved by the Department for a Facility Cost Centre is effective for 1994 and subsequent years unless the Department changes the factor and a written notice is given to the Facility Operator.

The Department may change a CPAF if:

a) an audit or validation done by the Department discovers that one or more of the 1990, 1991 or 1992 reports, upon which it relied to calculate the factor, is inaccurate; or
b) a FCC Operator submits a request to the Department *or*
c) a review by the Department demonstrates that the factor is inaccurate; or
d) a review by the Department demonstrates that the provincial Crown royalty share of custom processing is no longer reasonable.

Effective January 1, 1994, FCC operators who wish to revise their CPAF must submit a completed CPAF form (see Appendix P of the Principles and Procedures) to the Department. The Department will update the CPAF registry, before reporting the revised CPAF on the AC2.

Effective the 1997 production year, Facility Cost Centre Operators must recalculate the CPAF annually via submission of AC2 forms. Supporting information must be reported on Part 5 of the AC2-V2 *(Refer to Section 24.2.1)* to substantiate the reported CPAF. Facility Cost Centre Operators must track custom processing volumes to accurately file CPAFs.

It is imperative that operators of FCCs are made aware of all custom processing arrangements in order to accurately calculate CPAFs. Effective the 1994 production year, audit adjustments and penalties will be assessed to FCC Owners charging custom processing fees if they do not notify FCC Operators of the custom processing arrangements and associated volumes. The audit adjustment will disallow Capital Cost Allowance from owners failing to notify operators of custom processing arrangements at Facility Cost Centres. The Capital Cost Allowance of the other owners in the Facility Cost Centre will not be impacted by the audit adjustment. After the assessment of the audit adjustment, if owners still do not inform FCC Operators of the custom processing arrangement, they may also be assessed audit penalties.

16.7 Capital Cost Allowance Adjustment

Capital cost allowance will be recaptured through an annual adjustment at the client/EUB facility level for the following activities in the following order:

- Custom Processing *(Refer to Section 16.6)*;
- EOR *(Refer to Section 20.5)*; *and*
- Amortized Royalty Paid Banks *(Refer to Section 18.2.1)*.

However, at no time will the capital cost allowances after recapture at a client/EUB facility level be reduced to below zero.

16.8 Royalty Client's Annual Crown Share of Capital Cost Allowance

16.8.1 Re-Allocation of Capital Cost Allowance

S.17(11) A royalty client who has been allocated Capital Cost Allowance at a Facility Cost Centre may make a further allocation to other royalty clients. The Client Services Help Desk must receive the AC3 form, allocating Capital Cost Allowance to other royalty clients, Client Services, by May 15th of the year following the production year to which the costs relate. *(Refer to Section 24.3.)*

The Department calculates the Crown share of Capital Cost Allowance payable to each royalty client for a production year as:

> (total Capital Cost Allowance allocated from all Facility Cost Centres for the year
> ***...minus...***
> total Capital Cost Allowance allocated to other royalty clients for the year)
> ***...multiplied by...***
> royalty client's Corporate Effective Royalty Rate for the year

16.8.2 Corporate Effective Royalty Rate (CERR)

The Department calculates each royalty client's Corporate Effective Royalty Rate for a production year as:

> the Crown royalty value of the royalty client's corporate production for the year
> ***...divided by...***
> the corporate value of the royalty client's corporate production for the year

The Crown royalty value of a royalty client's corporate production for a year is:

> royalty client's qualifying Crown royalty share of gas and gas products for the year
> ***...multiplied by...***
> the price at which the Department values the royalty client's Crown royalty share of gas and each gas product for the year

A royalty client's qualifying Crown royalty share for each gas and gas product for a year is:

> total Crown royalty share for the year
> ***...minus...***
> Crown royalty holiday share for the year
> ***...minus...***
> Crown royalty share consumed and exempted from the payment of Crown royalty for the year
> ***...minus...***
> Crown royalty share sent to approved **cycling schemes*** for the year

The corporate value of a royalty client's corporate production for a year is:

> (total quantity of gas and gas products allocated to the royalty client for the year at all Alberta facilities *(including gas produced outside Alberta and processed in Alberta facilities)*
> ***...minus...***
> total quantity of gas and gas products injected by the royalty client in approved cycling schemes during the year)
> ***...multiplied by...***
> the price at which the Department values the royalty client's Crown royalty share of gas and each gas product for the year

NOTE: (1) ALL GAS AND GAS PRODUCTS DERIVED FROM PURCHASED VOLUMES WILL BE INCLUDED IN THE CALCULATION OF THE PURCHASER'S CERR.

(2) PROVISIONALLY ASSESSED VOLUMES WILL NOT BE INCLUDED IN CALCULATING THE CERR OF A ROYALTY CLIENT.

16.9 Operating Cost Centre Accountability

An **Operating Cost Centre*** *(formerly GCA facility)* is an account in which the Department accumulates **allowable operating costs*** for the purpose of calculating Crown share of Operating Cost Allowances. Operating Cost Centres may include the same facilities as a Facility Cost Centre.

An Operating Cost Centre may be a gathering system, compressor or processing plant, and may include all or a part of an EUB facility. An EUB facility, in this context, is the processing plant or gathering system where plant gate quantities of gas and gas products are reported for the purpose of determining accountability for Crown royalty reporting. Costs accumulated at Operating Cost Centres within an EUB facility are summed to the EUB facility level to develop Unit Operating Cost Rates. **Reconciliation Facility Groups*** are the exception to this rule.

A ***Reconciliation Facility Group***[1] is a collection of Operating Cost Centres that consists of a Department-approved grouping of EUB facilities that:

- report volumes and costs at various facilities within the Reconciliation Facility Group;
- include at least one facility that has an EUB-approved design capacity greater than 3,000 10^3m^3 per day; *and*
- include all volumes and costs of the Reconciliation Facility Group to establish a unique Unit Operating Cost Rate that will apply to all member facilities.

[1] Reconciliation Facility Groups existed before 1994. Those that included facilities with a design capacity greater than 3,000 10^3m^3 per day have been continued into 1994 to avoid the significant cost analysis and re-filing that would be required to calculate separate rates for the facilities involved. Operators of Reconciliation Facility Groups will report cost data for 1994, 1995 and 1996 to provide sufficient information so the Department can eliminate Reconciliation Facility Groups in 1997.

Facilities are classified as two types for the purpose of establishing unit operating cost rates.

- *Designated Facilities* are those that:
  - include one or more facilities with an EUB-approved design capacity greater than 3,000 10^3m^3 per day; *and*
- were operational at January 1, 1994. *(A list of Designated Facilities is provided in Appendix I)*
- ***Plant Type Facilities**** are those that:
  - were operational at January 1, 1994, and which have an EUB-approved design capacity that is 3,000 10^3m^3 per day or less; *and*
  - facilities of any design capacity that become operational on or after January 1, 1994.

S.17(6)(b) An Operator of a ***Designated Facility****, or an operator of an associated Facility Cost Centres tied to the Designated Facility, is required to provide annual reporting on the AC4 form to the Department describing the operating costs of the facility for the year. *(Refer to Section 24.4).* ****For definition, please see Appendix N – Glossary.***

The Client Services Help Desk must receive a form describing the operating costs of a Designated Facility on or before March 31 of the year following the production year to which the costs relate.

An operator of a *Plant Type Facility* is not required to provide annual operating cost reporting to the Department.

NOTE: FACILITY OPERATORS MAY REQUEST A REPORT FROM THE DEPARTMENT IDENTIFYING ALL THE ASSOCIATED FACILITY COST CENTRES TIED TO THEIR RESPECTIVE DESIGNATED FACILITIES.*

16.10 Classification of a New EUB Facility

Effective July 1, 1996, the Facility Operator must forward an application for the classification of a new EUB facility Plant Type Code to Gas Royalty Operations. This branch will process all applications, and will assign the EUB facility a Plant Type Code and a Transportation Region Code. Please use the AC10 form when applying for Plant Type Codes. This form is provided in Appendix P.

NOTE: APPLICATIONS FOR APPROVALS OF PLANT CONSTRUCTION/RE-ENGINEERING, ETC, MUST BE FORWARDED TO THE EUB.

16.10.1 Revising the Classification of an EUB Facility

An EUB facility operator may request a review of the classification of a *Plant Type* facility, or the Department may initiate such a review.

If the review is initiated by a facility operator, the request must be submitted in writing to the Team Leader, Client Services, and must:

- describe the reasons why the existing classification is inappropriate;

If a review by the Department shows that changes at either an existing facility or new facility:

- significantly distorts the current Unit Operating Cost Rate for the Plant Type in which the facility is classified; *or*
- are sufficient to warrant reclassification of the facility to a different Plant Type; *or*
- are sufficient to warrant the addition of a new Plant Type classification;

then the Department will take the necessary reclassification action.

If a change to Plant Type classification is made, the Department:

- will announce the change either directly to the applicant or through an *Information Bulletin,* whichever is more appropriate; and
- will include the change in the next update of the *Principles and Procedures* manual.

After 1994, the effective date of a change is:

a) January 1 of a year, if the plant re-construction/re-engineering has been approved by the EUB; and operation commences before April 1 and the request for the plant type change is received by the Department before April 1 of the same year; or

b) January 1 of the following year if operation commences after March 31; or operation commences before April 1 but the Department receives the request for the plant type after March 31. A request for a plant type change must be submitted to the Team Leader, Client Services.

c) The production periods to which annual Unit Operating Cost Rates apply are February 1 to January 31 of the following year. For example, if the effective date of a plant type reclassification is January 1, 1996, the effective date of the UOCR for that plant type will be **February 1, 1996 to January 31, 1997.**

FOR DEFINITION, PLEASE SEE APPENDIX N – GLOSSARY

16.11 Allowable Operating Costs

Allowable operating costs and non-allowable operating costs are described in *Appendix H.*

The Minister may approve additions/deletions to the list of allowable costs or require additions/deletions to the list of non-allowable costs. Where such an addition/deletion is approved or required, the Department:

- will announce the change in an *Information Letter*; *and*
- will include that change in the next update of the *Principles and Procedures* manual.

The amount of an allowable operating cost is either:

- the amount paid, net of any recoverable tax *(e.g., GST)*, in an arm's-length transaction; *or*
- the amount paid, net of any recoverable tax *(e.g., GST)*, in a **non-arm's-length*** transaction if the Department agrees that the amount is fair.

16.12 Calculating Crown Share of Operating Cost Allowances

The Department calculates the Crown share of Operating Cost Allowances monthly. They are calculated separately for each royalty client at each EUB facility through which the royalty client gathers, compresses or processes gas and gas products.

A royalty client's monthly Crown share of Operating Cost Allowances for an EUB facility is calculated as:

royalty client's Crown royalty share of **energy adjusted gas equivalent volumes***
at the plant gate of the EUB facility for the month *(including*
gas and products sent to approved injection and cycling schemes)
...multiplied by...
unit operating cost rate for the EUB facility in the month

A royalty client's total Operating Cost Allowances for a month is the sum of the calculated Crown share of Operating Cost Allowances for all of the EUB facilities in which the royalty client participates.

16.13 Unit Operating Cost Rates

The Department calculates Unit Operating Cost Rates in the production year to which they will apply. There are two types of Unit Operating Cost Rates (UOCR):

- *Designated Facility Rates* — one unique UOCR for each Designated Facility that is operational in the year; *and*
- *Plant Type Rates* — one unique UOCR for each of five plant types, as follows:
  Type 1 — dry gas with dehydration/compression, *or* gathering systems with sales;
  Type 2 — wet gas with dehydration, compression and C3+ extraction;
  Type 3 — dry gas with sulphur removal;
  Type 4 — wet gas with sulphur removal; and
  Type 5 — dry and wet gas with sulphur recovery.

A more complete description of the five plant types, a list of the Designated Facilities and the UOCRs for each are provided in *Appendix I.*

The Unit Operating Cost Rates for 1994 will apply to the 13-month period January 1, 1994 to January 31, 1995. The Unit Operating Cost Rates for subsequent years will apply to the 12-month period of February 1 to January 31 of the following year. The 1994 rates were revised after the1992 production year closed through a one-time adjustment, and published in the September 1995 Information Bulletin. Subsequent years' UOCR are only adjusted on a prospective basis.

16.13.1 Energy Adjusted Gas Equivalent Volume

Unit Operating Cost Rates are expressed in terms of dollars per 10^3m^3 of energy-adjusted gas equivalent volumes.

The energy-adjusted gas equivalent volume factors for gas and gas products are:

Product/Base Unit	*Gas Equivalent Factor*	*Energy Adjustment Factor*(1)	*Energy-Adjusted Gas Equivalent Factor (10^3m^3)*
GAS in 10^3m^3	1.00000	1.00	1.00000
ETHANE in m^3	0.28132	1.00 (2)	0.28132
PROPANE in m^3	0.27201	2.41	0.65554
BUTANE in m^3	0.23331	3.12	0.72793
PENTANES-PLUS in m^3	0.20570	3.83	0.78783
SULPHUR in tonnes	0.73750	1.00	0.73750
OTHER	0.00000	0.00	0.00000

(1) The *energy adjustment factor* for propane, butane and pentanes-plus includes a conversion to 39 MJ per m^3 of residue gas.

(2) The *energy adjustment factor* for ethane is the same as that of gas after it is converted to gas equivalent.

The energy-adjusted gas equivalent volume of gas or a gas product is calculated as:

quantity of gas or gas product *(expressed in base units)*
...multiplied by...
gas equivalent factor for the gas or gas product
...equals...
gas equivalent volume of the gas or gas product in 10^3m^3
...multiplied by...
energy adjustment factor for the gas or gas product
...equals...
energy-adjusted gas equivalent volume of the gas or gas product in 10^3m^3

The energy-adjusted gas equivalent volume *(in 10^3m^3)* may also be calculated by multiplying the gas or gas product *(in its base unit of measurement)* by the composite *energy-adjusted gas equivalent factor*.

The energy-adjusted gas equivalent volume factor for "Other Gas Products" for which the Minister has prescribed a Reference Price of zero *(refer to Section 15.5)* is also zero.

The gas equivalent conversion factors are the industry standard specified in the "Table of Physical Constants of Paraffin Hydrocarbons and Other Components of Natural Gas," as approved by the Gas Processors Association *(SI Engineering Data Book, GPA Publication 2145 SI-90)*. Any changes to these standards will apply in the production year following the year in which the change is made.

16.14 Calculating Unit Operating Cost Base Rates for 1994

The UOCRs for 1994 were calculated the same way for both the Designated Facilities and the Plant Types.

Each unique base rate was calculated as:

(operating costs for 1990, 1991 and 1992 *(expressed in mid-year 1994 dollars using the Canada GDP index)* for all Operating Cost Centres covered by the rate
...multiplied by...
1.025 *(allowances for return on working capital)*
...divided by...
energy-adjusted gas volume equivalents of 1990, 1991 and 1992 gas and gas products available for disposition for all Operating Cost Centres covered by the rate)
...multiplied by...
compensation factor*

Operating Costs for 1990, 1991 and 1992 were those reported to the Department by facility operators *(pre-1994 GC2 forms)*. Where the operating costs included costs for facilities in a Reconciliation Facility Group that was not continued in 1994, the Department assumed that operators had accurately allocated costs and volumes to each member facility. The resulting separated costs and volumes were included in the appropriate Plant Type for UOCR calculation.

The *cost escalation factor* was calculated using the Canada GDP index for January to December of each of the years.

The 1.025 factor is an allowance for return on working capital equal to 15% per annum on two months of operating costs.

The *energy-adjusted gas volume equivalents* were calculated as:

1990, 1991 and 1992 Volumes available for sale *(pre-1994 GV3 form)*
as reported to the Department *(including gas produced outside Alberta and processed in Alberta facilities)*
...multiplied by...
energy-adjusted gas equivalent factors described in *Section 16.13.1*

The *compensation factor* is intended to ensure that the overall impact to the Crown and the petroleum and natural gas industry is the same as if the *gas equivalent volumes* were not adjusted for the *energy content* of propane, butane and pentanes-plus.

The *compensation factor* was calculated as:

1990, 1991 and 1992 Crown share of operating cost allowances
calculated using Crown royalty share gas equivalent volumes
...divided by...
1990, 1991 and 1992 Crown share of operating cost allowances
calculated using Crown royalty share energy-adjusted gas equivalent volumes

16.15 Calculating Unit Operating Cost Rates for 1995 and Onwards

16.15.1 Updating Designated Facility Rates

The Department calculates the UOCR for each designated facility for the current year based on the previous year's actual costs/volumes. There is also a **rate adjustment*** to account for any changes to costs/volumes used to establish the previous year's UOCRs.

The UOCR for each Designated Facility for the current year is calculated as:

([(actual allowable Operating Cost for the previous year *...multiplied by...* Canada GDP index for the previous year)
...plus...
rate adjustment]
...divided by...
actual energy-adjusted gas equivalent volume of gas and gas products available for disposition at the facility for the previous year)
...multiplied by...
compensation factor

Represented by the following formula:

$$\left[\frac{(AAOCPY \times GDPPY) + RA}{AEAGEVPY}\right] \times CF$$

WHERE:

AAOCPY = ACTUAL ALLOWABLE OPERATING COST FOR THE PREVIOUS YEAR
GDPPY = CANADA GROSS DOMESTIC PRODUCT INDEX FOR THE PREVIOUS YEAR
RA = RATE ADJUSTMENT
AEAGEVPY = ACTUAL ENERGY ADJUSTED GAS EQUIVALENT VOLUME OF GAS AND GAS PRODUCTS AVAILABLE FOR DISPOSITION AT THE FACILITY FOR THE PREVIOUS YEAR
CF = COMPENSATION FACTOR

The *actual allowable operating costs* are those reported on the AC4 form by the Operating Cost Centre Operator for each Designated Facility.

The Canada GDP index is published in April as Catalog No. 13-001.

The *rate adjustment* comprises of an estimate-to-actual component for the previous year and an amendment component for each amended year, to account for any cost/volume differences in any previous year where there have been amendments.

For definition, please see Appendix N - Glossary.

For each Designated Facility, the Department calculates the *rate adjustment (estimate-to-actual component)* as:

[(actual allowable operating costs for the previous year *...minus...* estimated
allowable operating costs for the previous year)
...plus...
([(estimated energy-adjusted gas equivalent volumes for the previous year
...minus... actual energy-adjusted gas equivalent volumes for the
previous year) *...multiplied by...* UOCR for the previous year]
...divided by... compensation factor for the previous year)]
...multiplied by...
Canada GDP index for the previous year

Represented by the following formula:

WHERE:

$$\left[(AAOCPY - EAOCPY) + \frac{(EEAGEVPY - AEAGEVPY) \times UOCRPY}{CFPY}\right] \times GDPPY$$

AAOCPY = Actual Allowable Operating Costs for the Previous Year
EAOCPY = Estimated Allowable Operating Costs for the Previous Year
EEAGEVPY = Estimated Energy Adjusted Gas Equivalent Volumes for the Previous Year
AEAGEVPY = Actual Energy Adjusted Gas Equivalent Volumes for the Previous Year
UOCRPY = Unit Operating Cost Rate for the Previous Year
CFPY = Compensation Factor for the Previous Year
GDPPY = Canada Gross Domestic Product Index for the Previous Year

For each Designated Facility, the Department calculates the *rate adjustment (amendment component by amended year)* as:

[(actual allowable operating costs for the amended year *...minus...* previous actual allowable operating costs for the amended year)
...plus...
([(previous actual energy-adjusted gas equivalent volumes for the amended year *...minus...* actual energy adjusted gas equivalent volumes for the amended year) *...multiplied by...* UOCR for the amended year] *...divided by...* compensation factor for the amended year)]
... multiplied by...
(Canada GDP index for the amended year *...multiplied by...* Canada GDP index for each of the intervening year[s]$^{(1)}$)

Represented by the following formula:

$$\left[(AAOCAY - PAAOCAY) + \frac{(PAEAGEVAY - AEAGEVAY) \times UOCRAY}{CFAY}\right] \times (GDPAY \times GDPIY)$$

WHERE:

AAOCAY = Actual Allowable Operating Costs for the Amended Year
PAAOCAY = Previous Actual Allowable Operating Costs for the Amended Year
PAEAGEVAY = Previous Actual Energy Adjusted Gas Equivalent Volumes for the Amended Year
AEAGEVAY = Actual Energy Adjusted Gas Equivalent Volumes for the Amended Year
UOCRAY = Unit Operating Cost Rate for the Amended Year
CFAY = Compensation Factor for the Amended Year
GDPAY = Canada Gross Domestic Product Index for the Amended Year
GDPIY = Canada Gross Domestic Product Index for each of the Intervening Year(s)

(1) Amendment adjustments will be escalated by the GDP index for each of the intervening years as well as the GDP index for the amended year.

The *compensation factor* for each year is calculated as:

(Crown royalty gas equivalent volume for the previous year *...multiplied by...* previous year's uncompensated gas equivalent UOCR)
...divided by...
(Crown royalty energy-adjusted gas equivalent volume for the previous year *...multiplied by...* previous year's uncompensated energy-adjusted gas equivalent UOCR)

16.15.2 Updating "Plant Type" Rates

The Department calculates the UOCR for each of the five *Plant Types* for the current year based on the previous year's actual volumes and rate adjustment to account for any changes to volumes used to establish previous UOCRs.

The UOCR for each Plant Type for the current year is calculated as:

([(projected allowable operating cost for the previous year(1) *...multiplied by...*
Canada GDP index for the previous year)
...plus...
rate adjustment]
...divided by...
actual energy-adjusted gas equivalent volume of gas and gas products available
for disposition at all facilities in the Plant Type for the previous year)
...multiplied by...
compensation factor

Represented by the following formula:

$$\left[\frac{(PAOCPY \times GDPPY) + RA}{AEAGEVPY}\right] \times CF$$

WHERE:

PAOCPY = PROJECTED ALLOWABLE OPERATING COST FOR THE PREVIOUS YEAR

GDPPY = CANADA GROSS DOMESTIC PRODUCT INDEX FOR THE PREVIOUS YEAR

RA = RATE ADJUSTMENT

AEAGEVPY = ACTUAL ENERGY ADJUSTED GAS EQUIVALENT VOLUME OF GAS AND GAS PRODUCTS AVAILABLE FOR DISPOSITION AT ALL FACILITIES IN THE PLANT TYPE FOR THE PREVIOUS YEAR

CF = COMPENSATION FACTOR

(1) For 1994, the projected allowable operating cost for the previous year is the weighted average of 1990, 1991 and 1992 costs expressed in *mid-year 1994* dollars. In subsequent years, it is the projected allowable operating cost for the previous year.

The *rate adjustment* comprises of an estimate-to-actual component for the previous year and an amendment component for each amended year, to account for any volume differences in any previous year where there have been amendments.

For each *Plant Type*, the Department calculates the *rate adjustment (estimate-to-actual component)* as:

([(estimated energy-adjusted gas equivalent volumes for the previous year
...minus... actual energy-adjusted gas equivalent volumes for the previous year)
...multiplied by... UOCR for the previous year]
...divided by... compensation factor for the previous year)
...multiplied by...
Canada GDP index for the previous year

Represented by the following formula:

$$\left[\frac{(EEAGEVPY - AEAGEVPY) \times UOCRPY}{CFPY}\right] \times GDPPY$$

WHERE:

EEAGEVPY = ESTIMATED ENERGY ADJUSTED GAS EQUIVALENT VOLUMES FOR THE PREVIOUS YEAR

AEAGEVPY = ACTUAL ENERGY ADJUSTED GAS EQUIVALENT VOLUME OF GAS AND GAS PRODUCTS AVAILABLE FOR DISPOSITION AT ALL FACILITIES IN THE PLANT TYPE FOR THE PREVIOUS YEAR

UOCRPY = UNIT OPERATING COST RATE FOR THE PREVIOUS YEAR

CFPY = COMPENSATION FACTOR FOR THE PREVIOUS YEAR

GDPPY = CANADA GROSS DOMESTIC PRODUCT INDEX FOR THE PREVIOUS YEAR

For each *Plant Type*, the Department calculates the *rate adjustment (amendment component by amended year)* as:

([(previous actual energy-adjusted gas equivalent volumes for the amended year
...minus... actual energy-adjusted gas equivalent volumes for the amended year)
... multiplied by... UOCR for the amended year]
... divided by... compensation factor for the amended year)
...multiplied by...
(Canada GDP index for the amended year ...multiplied by... Canada GDP index for each of the intervening year(s)[1])

[1] Amendment adjustments must be escalated by the GDP for each of the intervening years, as well as the GDP for the amended year.

Represented by the following formula:

$$\left[\frac{(PAEAGEVAY - AEAGEVAY) \times UOCRAY}{CFAY}\right] \times (GDPAY \times GDPIY)$$

WHERE:

PAEAGEVAY = PREVIOUS ACTUAL ENERGY ADJUSTED GAS EQUIVALENT VOLUMES FOR THE AMENDED YEAR

AEAGEVAY = ACTUAL ENERGY ADJUSTED GAS EQUIVALENT VOLUME OF GAS AND GAS PRODUCTS AVAILABLE FOR DISPOSITION AT ALL FACILITIES IN THE PLANT TYPE FOR THE AMENDED YEAR

UOCRAY = UNIT OPERATING COST RATE FOR THE AMENDED YEAR

CFAY = COMPENSATION FACTOR FOR THE AMENDED YEAR

GDPAY = CANADA GROSS DOMESTIC PRODUCT INDEX FOR THE AMENDED YEAR

GDPIY = CANADA GROSS DOMESTIC PRODUCT INDEX FOR EACH OF THE INTERVENING YEAR(S)

16.16 Calculating Annual Crown Share of Custom Processing Cost Allowance

16.16.1 Calculation Criteria

A royalty client who has paid for compressing, gathering or processing gas and gas products on a *fee-for-service* basis must file an AC5 document to claim a Custom Processing Cost Allowance. This claim also includes fees associated with freehold, purchased and out-of-province volumes. Failure to file the AC5 document by its legislated due date will result in late filing penalties.

Custom Processing Fees For 100% Freehold Royalty Clients

The only exception to this rule applies to royalty clients who do not pay any Crown royalty nor receive a Crown Cost Allowance during the production year unless they have been amalgamated or consolidated with a Crown royalty client.

Effective from the 1995 production year, clients that are 100% freehold are no longer required to file an AC5 document for the related production year as long as they do not acquire any Crown interest volumes in the same production year. In the event that your freehold status changes during the year and as a consequence you are required to file an AC5 to claim custom processing fees, the Department encourages timely filing of the AC5 to prevent late filing penalties.

For 100% freehold royalty clients who may receive a Crown Cost Allowance through amalgamation or consolidation with a Crown Royalty client, all processed volumes are subject to operating cost recapture in the absence of capital ownership. Filing an AC5 document to report the custom processing fees paid on freehold volumes entitles the royalty client to a Crown Cost Allowance in excess of operating costs.

In situations where royalty clients own part of a delayered facility and paid for custom processing in the same delayered component, they may submit a written request to the Department requesting the monthly operating costs in lieu of receiving custom processing for the facility. The written request must include supporting documentation that provides evidence that they are disadvantaged due to operating cost recaptures exceeding the custom processing paid in the production year. Once approved, in the subsequent production years, the Crown will continue to recognize an operating cost deduction in lieu of custom processing for the facility. No further custom processing fees will be recognized at the facility by the Crown. Royalty clients must continue to submit the AC5 form providing custom processing fees and volumes to the Department on an annual basis.

S.17(10) The AC5 form describing the custom processing fees paid in a year by a royalty client must be received by the Client Services Help Desk by May 15 of the year following the production year in which the payments were made *(refer to Section 24.5)*. This does not apply to pre-1994 business.

Annually, the Department calculates the Crown share of Custom Processing Cost Allowances for each royalty client, net of the monthly Crown share of Operating Cost Allowances already paid.

The Department calculates each royalty client's annual Crown share of Custom Processing Cost Allowances as:

net custom processing fees paid in the production year by the royalty client
...multiplied by...
royalty client's Corporate Effective Royalty Rate for the year

Calculation of a royalty client's *Corporate Effective Royalty Rate* is described in *Section 16.8.2.*

Net custom processing fees paid in the production year by a royalty client are:

eligible custom processing fees paid in the production year
...minus...
allowable operating cost on **all** custom processed gas and gas products for the year

16.16.2 Eligible Custom Processing Fees

Eligible custom processing fees paid are arm's-length fees paid by the royalty client:

- for compressing, gathering or processing services at an EUB facility in which the royalty client has no ownership interest; *or*
- to co-owners of a Facility Cost Centre in which the royalty client has an ownership interest, for the quantity of gas and gas products processed that exceed the royalty client's ownership share *(these fees must be defined clearly in writing in the partnership or joint venture agreement.)*

S.17(3)

NOTE: - ELIGIBLE CUSTOM PROCESSING FEES DO NOT INCLUDE OFFSETTING CONSIDERATIONS BETWEEN THE CLIENT AND THE PROCESSOR, OR WHERE TRANSACTIONS ARE ESSENTIALLY A FINANCING MECHANISM. THE CROWN MAY LIMIT CUSTOM PROCESSING FEES TO A REASONABLE AMOUNT, AS DETERMINED BY THE MINISTER, FOR A ROYALTY CLIENT WHO PAYS FEES FOR COMPRESSING, GATHERING OR PROCESSING AT AN EUB FACILITY IN WHICH HE PREVIOUSLY HAD AN OWNERSHIP INTEREST.

- A ROYALTY CLIENT REPORTING CUSTOM PROCESSING FEES MUST HAVE A VOLUMETRIC ALLOCATION (THROUGH OAS AND/OR RMF2) AT THE FACILITY FOR THE PRODUCTION YEAR. IF A ROYALTY CLIENT REPORTS CUSTOM PROCESSING FEES AT THE FACILITY WHERE THEY DO NOT HAVE ANY VOLUMES FOR THE PRODUCTION YEAR, THE CUSTOM PROCESSING FEES WILL BE DISALLOWED.

A royalty client reporting custom processing fees must have either OAS or RMF2 volumes at the facility for that production year. If a royalty client reports custom processing fees at a facility where they do not have any volumes for the production year, the custom processing fees will be disallowed.

If a royalty client obtains custom processing services for a fee or consideration other than money, *then*:

- where the fee is paid as gas or a gas product, the eligible amount of the fee is:

the quantity of the gas or gas product given in payment ***...multiplied by...*** the price at which the Department values the Royalty client's gas or gas product given in payment

- where the fee is paid with other than gas or a gas product, the eligible amount of the fee is the **market value***) of the goods or services given in payment.

Prepaid custom processing costs claimed in a year must be that portion of the total prepaid cost that relates to the actual volume processed in that year.

The Crown reserves the right, as defined in *Section 17(3) of the Natural Gas Royalty Regulation 1994*, to limit the custom fees paid by the custom user to a share of total costs at the Facility Cost Centre proportional to the custom user's volumes.

NOTE: IF APPROVED BY THE MINISTER, WHEN UNPROCESSED GAS IS DELIVERED TO A FIELD STRADDLE PLANT FOR PROCESSING BEFORE BEING DISPOSED OF, THE DEPARTMENT WILL ASSESS CROWN ROYALTY SHARE OF GAS AND GAS PRODUCTS AT THE PLANT GATE OF THE FIELD STRADDLE PLANT. ALLOWABLE COSTS WILL BE GIVEN THROUGH A REASONABLE CUSTOM PROCESSING FEE EQUIVALENT TO THE ACTUAL COSTS FOR THAT PLANT. NO OPERATING COST WILL BE RECAPTURED BECAUSE FIELD STRADDLE PLANTS HAVE NOT BEEN GIVEN A UOCR.

For definition, please see Appendix N - Glossary.

16.16.3 Allowable Operating Cost on Custom Processed Gas and Gas Products

The volumes of gas and gas products for which a royalty client paid eligible custom processing fees in a year will have had a UOCR applied to them each month. As a result, the Crown will have paid the Crown share of Operating Cost Allowances on them. A royalty client's eligible custom processing fees for a year (including fees associated with freehold, purchase and out-of-province gas and gas products) will be reduced at the Initial Annual Billing Period (IABP) by the amount of the operating costs. The operating cost for this purpose applies to all gas and gas product volumes including freehold, purchased and out-of-province gas and gas products.

If the eligible custom processing fee paid is for all of the royalty client's volumes at the EUB facility and all of the services provided by the facility, *then* the *Allowable Operating Cost* will be subtracted from the eligible custom processing fees paid, calculated as:

> royalty client's share of energy-adjusted gas equivalent volumes custom processed at the EUB facility for the year *(including gas and products sent to approved injection and cycling schemes)*
> ***...multiplied by...***
> UOCR for the EUB facility in the year

If the eligible custom processing fee paid is only for a part of the services and/or part of the volumes provided by an EUB facility, *then* the *Allowable Operating Cost* that must be subtracted from the eligible custom processing fees paid will also be only part of the Allowable Operating Cost for the facility at which the services were provided.

The reduction for *partial custom processing* service is recognized through pro-rating the UOCR for the EUB facility into three *delayered rates*; one each for compressing, gathering and processing.

The Allowable Operating Cost that will be deducted for partial custom processing service is calculated as:

> royalty client's energy-adjusted gas equivalent volume custom processed at the EUB facility for the year (1) *(including gas and products sent to approved injection and cycling schemes)*
> ***...multiplied by...***
> delayered compressing/gathering/processing UOCR(2) for the EUB facility for the year

(1) Energy-adjusted gas volume equivalent of the custom processed gas and gas product volumes reported by the royalty client on the AC5 form(s) for the year.

(2) Delayered compressing UOCR, delayered gathering UOCR or delayered processing UOCR, or any combination of them depending on the service provided.

NOTE: A YEAR-END CLOSE-OUT PROCESS WILL RECAPTURE OPERATING COSTS FROM A ROYALTY CLIENT WHO HAS VOLUMES AT A FACILITY WHERE THEY HAVE NO CAPITAL OWNERSHIP(AS IDENTIFIED ON THE AC2 OR AC3 FORMS) AND NO REPORTED CUSTOM PROCESSING FEES. A ROYALTY CLIENT WHO IS NOT AN OWNER AT A FACILITY IS NOT ENTITLED TO THE OPERATING COSTS THEY RECEIVED ON A MONTHLY BASIS. THEREFORE, THE OPERATING COSTS WILL BE RECAPTURED IF THERE HAVE BEEN NO REPORTED CUSTOM PROCESSING FEES ON THE AC5. THIS ANNUAL CUSTOM PROCESSING ADJUSTMENT, AS WITH ALL OTHER CUSTOM PROCESSING AMENDMENTS, WILL BE SUBJECT TO PRIOR PERIOD INTEREST.

IF A ROYALTY CLIENT HAS OWNERSHIP INTEREST IN A FACILITY COST CENTRE AND IS ALSO PAYING CUSTOM PROCESSING FEES FOR PROCESSING EXCESS VOLUMES AT THE SAME FACILITY COST CENTRE, THEN UOCR WILL NOT BE RECAPTURED BECAUSE EXCESS CAPACITY CHARGE IS INTENDED TO COVER THE CAPITAL AND PROFIT PORTION OF CUSTOM PROCESSING AND THEREFORE HAS NO OPERATIONAL EXPENSE COMPONENT FROM WHICH UOCR SHOULD BE DISALLOWED. IN NO CASE IS A ROYALTY CLIENT TO RECEIVE DUPLICATE UOCR ROCOGNITION.

16.17 Delayered Unit Operating Cost Rates

The segregation of allowable operating costs for the three categories, based on established Allowable Cost *(formerly GCA)* codes, is:

- *COMPRESSING* includes only those facilities coded as "COMPRESSOR".
- *GATHERING* includes only those facilities coded as "GATHERING SYSTEM".
- *PROCESSING* includes those facilities coded as:

GAS PLANT
SALES LINE AFTER PLANT
PRILLER/SLATER
DEHYDRATOR

LIQUID LINE
REMELTER
SEPARATOR
SULPHUR FACILITIES

Delayered Unit Operating Cost Rates* for 1994 for each Designated Facility and Plant Type were calculated as follows.

(1990, 1991 and 1992 compressing costs(1)
...divided by...
1990, 1991 and 1992 allowable operating costs(2))
...multiplied by...
1994 UOCR for the Designated Facility or Plant Type
...equals...
Delayered Compressing UOCR for the Designated Facility or Plant Type.

(1990, 1991 and 1992 gathering costs(1)
...divided by...
1990, 1991 and 1992 allowable operating costs(2))
...multiplied by...
1994 UOCR for the Designated Facility or Plant Type
...equals...
Delayered Gathering UOCR for the Designated Facility or Plant Type.

(1990, 1991 and 1992 processing costs[1]
...divided by...
1990, 1991 and 1992 allowable operating costs[2])
...multiplied by...
1994 UOCR for the Designated Facility or Plant Type
...equals...
Delayered Processing UOCR for the Designated Facility or Plant Type.

(1) Compressing costs, gathering costs and processing costs for 1990, 1991 and 1992 are the allowable operating costs for those same years split according to the above Allowable Cost codes, expressed in mid-year 1994 dollars.

(2) Allowable operating costs for 1990, 1991 and 1992 are those reported to the Department by Facility Operators (pre-1994 GC2 forms), expressed in mid-year 1994 dollars.

Designated Facility's delayered UOCR for 1995 and subsequent years are calculated in the same manner as above for each designated facility:

(actual allowable compressing/gathering/processing costs for the previous year
...divided by...
actual allowable operating costs for the previous year)
...multiplied by...
UOCR for the current year
...equals...
delayered compressing/gathering/processing UOCR for the designated facility for the current year

Plant type delayered UOCR for 1995 and subsequent years is calculated using the compressing, gathering and processing splits calculated for 1994, since there is no allowable operating cost reporting for plant types from 1994 onwards.

****For definition, please refer to Appendix N, Glossary***

17. Other Programs Administered with Natural Gas Royalty

17.1. Valuing and Reporting Field Condensate

Effective January 1, 1994, the monthly Crown royalty share of *field condensate* is valued using the *Pentanes Reference Price* in effect for the production month, reduced by the applicable *Transportation Allowances* for pentanes plus, propane and butane contained in a natural gas liquids mix. *Section 15.2.1* provides a description of the business rules for Pentanes Reference Price. *Section 15.3.1.* provides a description of the business rules for Regional Transportation Allowances.

Until further notice from the Department, field condensate Crown royalty will continue to be reported to the Department using the Petroleum Royalty Condensate Crown Royalty Detail *(PC1 form)*. *However,* the due date for filing a *PC1* form for a production month is changed to the last day of the third month following the production month. *(e.g. for the production month of January, the PC1 form is due April 30.)*

In regards to field condensate, (*Refer to Section 8.1*) the following process will be in effect until condensate royalty calculation procedure is automated and included in the monthly MRIS invoice, as part of future enhancements.

- Effective with production month January 1997, Gas Operations will assume all responsibilities from the Petroleum Royalty Branch in respect to condensate royalty.
- Operators are no longer required to calculate and report condensate royalty, including amendments to pre-1997 production, on the *PC1*. Gas Operations will obtain each well's condensate production from EUB's "S" reports, calculate condensate royalty at the battery level and issue an invoice to the operator of the battery.
- The monthly Crown royalty share of condensate is determined under Schedules 2 and 3 of the Petroleum Royalty Regulation and is valued using the Pentanes Reference Price in effect for the production month, reduced by the applicable regional transportation allowance for pentanes plus, propane and butane contained in a natural gas liquid mix.
- The Condensate Royalty Invoice will be issued by the last day of the second month following the production month. Payment is due on or before the last day of the third month following the production month. For example, the invoice for production month of January 1997 will be issued by March 31, 1997. Payment will be due April 30, 1997. Interest is charged on late payments from the due date.
- Each operator will receive one invoice for all batteries they operate, together with documentation supporting the condensate royalty calculation, including a production report for the wells in each battery and a royalty share calculation report for each battery.

17.1.2 Allowable Costs for Field Condensate

There are no *Allowable Costs* applicable to *field condensate,* as no compressing, gathering or processing will have taken place.

17.2 Offset Compensation (Formerly known as Compensatory Royalty)

NOTE: THE MINERAL TENURES BRANCH OF THE MINERALS TENURES DIVISION ADMINISTERS THE GAS OFFSET COMPENSATION. PLEASE CONTACT MARILYN BEKOLAY AT (780) 422-9158 IF YOU REQUIRE ADDITIONAL INFORMATION.

Offset Compensation is one of four options available to a Crown lessee who has been served with an ***offset notice**** on a Crown lease.

The Department will serve a Crown lessee *(or lessees)* with an *offset notice* where an **offset drilling obligation*** is created. This obligation occurs when a leased Crown spacing unit in which there is no well producing laterally adjoins a freehold spacing unit in which there is a producing well.

A Crown lessee who has been served with a *gas offset notice* may elect one of the following options:

- Drill a well to the offset zone in the Crown spacing unit and determine whether or not the offset zone is productive and if the offset zone in the Crown spacing unit is productive, complete the well and commence the production of petroleum or natural gas from that zone
- Surrender down to the base of the offset zone, excepting any zone in which a producing well is completed and any zone that is subject to a unit agreement or gas storage agreement
- Provide proof the freehold well is abandoned as to the offset zone; that the spacing unit for the freehold well is reduced and no longer adjoins the Crown spacing unit, or that the offset zone with the Crown spacing unit becomes subject to a unit agreement or gas storage agreement.
- Elect to pay Offset Compensation in writing on the petroleum and natural gas produced from the freehold well.

If a Crown lessee elects to pay Offset Compensation:

- the Department will invoice the Crown lessee for the monthly Offset Compensation for the subject Crown spacing unit;
- the monthly Offset Compensation will be calculated on the natural gas produced and recovered from the freehold lease in the month in the same manner as if the same quantity of natural gas had been produced and recovered from the subject Crown spacing unit;
- a factor of 41, or such number as determined by the Minister, will be used to convert 10^3m^3 to GJ;
- the vintage of the Crown spacing unit will be determined in the same manner as for a conventional Crown lease well event, and the *old* or *new gas* Crown royalty rate will be applied accordingly;
- the Crown royalty share of the subject production will be valued at 80% of the *Gas Reference Price* in effect for the production month;
- there will be no deduction for *Allowable Costs (the 20% reduction from Gas Reference Price is provided as an allowance for costs)*; *and*
- for the first 12 months, Offset Compensation payable is one half the amount that would have been payable. Thereafter, it is 100%. (***For definition, please see Appendix N – Glossary)**.

17.3 Trespass Damages

NOTE: THE MINERAL TENURES BRANCH OF THE MINERAL TENURES DIVISION ADMINISTERS TRESPASS DAMAGES. PLEASE CONTACT MARILYN BEKOLAY AT (780) 422-9158 IF YOU REQUIRE ADDITIONAL INFORMATION.

Trespass Damages are payable to the Crown when a mineral is recovered from undisposed Crown mineral rights *(i.e., a Crown mineral rights lease)*. For petroleum and natural gas, ***trespass**** can occur when a well is drilled into a zone for which the Crown mineral rights have not been leased, *or* where the rights to a zone have been severed from an existing Crown mineral rights lease and production from that zone continues after the rights are severed.

Trespass may be determined to be either *intentional* or *unintentional*. ***Intentional trespass**** will be assumed in every case. It is the responsibility of the person who commits trespass to demonstrate to the Crown that the trespass is *unintentional*. ***Unintentional trespass**** occurs when the trespasser demonstrates to the Crown's satisfaction that he was not aware that his actions constituted trespass.

If a person receives notice from the Department that he is committing *trespass* against the Crown's mineral rights, yet continues the action, damages due to the Crown will be determined.

Trespass Damages are the value of the mineral recovered from the unauthorized location. If a *trespass* is determined, the *Trespass Damages* due to the Crown will be calculated as follows:

- the trespass volumes will be calculated as the *Crown interest share* of the quantity of production recovered from the unauthorized location;
- the value of the trespass volumes will be determined using the *reference price(s)* in effect for the recovered mineral(s) for each month during which the trespass continued; *and*
- the value of the trespass volumes will be reduced by any royalty already paid to the Crown on the trespass volumes.

If the trespass is determined to be *unintentional trespass*, the *Trespass Damages* determined by the Crown will be reduced by the *reasonable direct allowable costs incurred* by the trespassing person to produce and market the trespass volumes. If the trespass is determined to be *intentional trespass*, there will be no reduction made for costs.

Should the damages calculation result in a negative amount, it will be equated to zero. The Crown because of this damages calculation, will not be placed in the position of recompensing the trespasser for costs incurred or royalty previously assessed.

Interest will be payable to the Crown on underpayment or late payment of *Trespass Damages* starting on the first day after the invoice due date and continuing until the date the payment is received.

For definition, please see Appendix N - Glossary.

17.4 Sulphur Emission Control Assistance Program (SECAP)

The basic requirements for *SECAP* eligibility are (*Refer to Section 8.2*):

1. the sulphur recovery process employed must be an *eligible process* approved by the EUB after July 6, 1988;
2. the subject gas processing plant must have a *sulphur equivalent inlet rate* of 1.0 to 5.0 tonnes per day; and
3. the subject gas processing plant must have a *sulphur recovery rate* of 70% or higher.

Gas processing plants approved before July 6, 1988 may qualify for 50% of eligible operating costs if they meet requirements two and three above.

A more detailed description of the program and requirements may be found in *Information Letter 89-21* or by reference to *Alberta Regulation 275/89.*

The operator *(Facility Operator)* of the gas processing plant who wishes to establish eligibility for *SECAP* is to apply to the Department for approval.

The procedures for preparing a *SECAP* application *(595 form)* are described in *Section 20.6*

For definition, please see Appendix N - Glossary.

18. Special Provisions for Transition from Pre-1994

18.1 Overview

There are three key business activities that require *transitional* provisions to ensure royalty clients and the Crown are able to adequately manage the change from pre-1994 processes. Two of these activities (royalty paid banks *(Section 18.2)* and Crown royalty liable inventory (*Section 18.3)*) will be managed through the *amortization* processes. The third, *commercial storage schemes (Section 18.4 and 5.3.2)* will be addressed through a one-time entry to establish balances.

18.2 Crown Royalty Paid Banks

18.2.1 Conversion to Native Status

The Crown will *"revert"* its royalty share of gas and gas products in *royalty paid banks* at December 31, 1993, and restore those royalty paid banks to native status *(for Crown royalty purposes)* effective January 1, 1994.

S.28(4)(b) The Crown's *"amortization"* of royalty paid banks will occur through credits calculated and applied to a royalty client's *invoice,* as follows:

- Closing royalty paid bank balances at December 31, 1993, will be determined from royalty client records on May 31, 1994, in 10^3m^3 and GJ for gas/ethane, and in m^3 for natural gas liquids, subject to audit by the Crown. In the absence of any GJ records, the client's GV6 Royalty Paid Bank gas balance will be multiplied by the **gigajoule*** conversion for Raw Gas;
- The Department will accept a royalty client's determination of the gigajoule opening balance for January 1994 if that royalty client has maintained the heat content records (of gigajoules injected and recovered) for at least two years starting January 1993. The 1994 opening balance is subject to audit;
- The *Crown interest share* of gas and gas products in a royalty paid bank is calculated using the Crown interest factors of the *injection scheme* from which the gas and gas products will be recovered. The gross amortization credit for each royalty paid bank is calculated at the injection facility level;
- A net royalty paid bank amount that is less than or equal to $100,000 per product/facility/client will be payable by the Crown in one payment;

S.28(3)(5) Royalty paid bank credits will generally be calculated using a *72-month amortization* of the established royalty paid bank balances. (*At the Minister's discretion, the Department may direct that the whole amount of a royalty client or a royalty paid bank is payable in one payment, and value it as if it is produced and subject to Crown royalty in January 1994.)*;

- S.28(4)(a) The Department calculates the Crown royalty share of a royalty paid bank that is amortized in a month using the Crown royalty formula applicable to the amortized product in the same month;
- The Department values the Crown royalty share of the amortized product (*the gross amortization credit)* using the same price that would apply if the same volume/quantity were subject to Crown royalty in the same month;

****For definition, please see Appendix N - Glossary.***

S.28(6)

- The monthly gross amortization credit will be reduced by the *operating cost allowances* calculated using the *Unit Operating Cost Rate(s)* of the gas processing plant where the gas and gas products are expected to be processed; *and*
- Capital Cost Allowances and Custom Processing Fee Allowance will be recovered through an annual adjustment at the client/EUB facility level where the gas and gas products are expected to be processed. The Capital Cost Allowance and Custom Processing Fee Allowance after recovery will not be less than zero.

The annual adjustment for each royalty paid bank participant at each client/EUB facility level is calculated as follows:

total royalty client's annual capital cost allowances/custom processing fees
...multiplied by...
the royalty client's annual gas equivalent volume of the amortized royalty paid bank
...divided by...
the royalty client's annual gas equivalent volume of total production

NOTE: THE DEPARTMENT HAS DETERMINED THAT INJECTION OF RICH GAS IN ONE AREA OF A RESERVOIR AND PRODUCTION OF DRY GAS FROM ANOTHER AREA COULD RESULT IN AN INCREASE IN THE HEAT CONTENT OF A RESERVOIR WITHOUT INCREASING THE VOLUME CONTENT. THE DEPARTMENT HAS AGREED TO PAY OUT HEAT CONTENT BALANCES THAT EXIST WITHOUT A VOLUMETRIC BALANCE, BUT WILL NOT PAY OUT VOLUMETRIC BALANCES WITHOUT A HEAT CONTENT BALANCE.

The Department has performed an adjusting process following the close-out of the 1992 and 1993 gas royalty business years. This accommodates the amendments and adjustments to pre-1994 records that may have an impact on Crown royalty paid bank balances. The amendments will be implemented on a go-forward basis.

The total net amortization credit for royalty paid banks will be reported on the monthly invoice. No interest will be charged or paid on the *Crown Royalty Paid Bank* settlement transactions and on subsequent amendments.

18.2.2 Royalty Paid Bank Transfer Rules

At the Minister's discretion, the Crown will recognize transfers of royalty paid banks where the transfer is a consequence of **natural succession***, or when all the following conditions exist:

- the royalty paid bank transfer is the result of a sale of a royalty client's working interest share in the reservoir;
- the seller transfers their entire portion of the bank, including all products, to another royalty client (partial bank transfers or transfers to more than one royalty client will not be recognized);
- a written and signed agreement from the purchaser and seller must be submitted to the Department to transfer the bank. The agreement must state the effective date of the sale, the injection facility, and client IDs of both the purchaser and seller;
- the seller's Crown interest in the reservoir will be transferred to the purchaser; *and*
- if the purchaser already has working interest in the reservoir, then a new weighted average Crown interest will be calculated for the purchaser.

******For definition, please see Appendix N - Glossary.***

The following rules apply to royalty paid bank transfers:

- bank transfers will not be recognized retroactively. The effective date of a bank transfer will be the first day of the second month following the month the Department receives the written and signed agreement (assuming all transfer conditions are satisfied). However, for bank transfers effective in 1994 and 1995, if the written agreement is received by the Department on or before June 15, 1995, and all conditions are satisfied, the transfer will be effective the first day of the month of the sale;
- Should the effective transfer dates conflict, the Department will recognize only the transfer date reported on the agreement received first. Conflicting dates reported on subsequently received agreements will not be recognized.
- the purchaser will assume all responsibilities and obligations of the seller for the bank including any and all prior period and audit adjustments. Please note: the seller will continue to be responsible for filing all pre-1994 royalty paid bank documentation with the Department; *and*
- annual adjustments to the purchaser's royalty calculation will also be applied to the Royalty Paid Bank credit received by the purchaser.
- if a royalty client sells his working interest ownership (WIO) in the reservoir and his ownership interest in the associated reprocessing facility, but retains his rights to the royalty paid bank credits, then the Department will recapture Capital Cost Allowance (CCA) for the annual amortized Royalty Paid Bank volumes based on the following methodology:

Royalty client's ownership interest in the Facility Cost Centre (FCC) tied to the reprocessing EUB facility at the time of sale
(. . . .multiplied by. . . .)
Total Capital Cost Allowance (net of CPAF) for the FCC in the year of recapture
(. . . multiplied by. . .)
The recapture percentage.

The recapture percentage is calculated as follows:

Royalty client's annual Gas Equivalent Volume (GEV) of the annual amortized Royalty Paid Bank Volumes for the year of recapture
(. . . .divided by. . . .)
Royalty client's share of annual GEV volume of the total facility production in the year of sale.

The royalty client's ownership interest in the FCC at the time of sale and the royalty client's share of the annual GEV volumes of the total facility production in the year of sale will remain constant for all subsequent amortization years.

18.3 Eliminating the Crown Royalty Share of Inventories

The Department will calculate the amount owed the Crown on account of undischarged Crown royalty inventory, for each *active Reporting Entity (REN)*, at December 31, 1993, as follows:

- S.29(2)(b) Crown gas royalty volumes ($10^3 m^3$) of undischarged inventory will be converted to gigajoules (GJ) using the average gigajoule content of gas transported in the Nova system during the month of December 1993 (39.05345);
- S.29(2)(c) the Crown royalty share of undischarged pentanes-plus inventory will be determined by using the *pentanes par price* for January 1994. For pentanes-plus, the Crown royalty volumes for each month will be valued at that month's reference price *less* transportation. No storage deduction will be allowed for pentanes-plus. For butane and propane, the Crown royalty volumes for each month will be valued at that month's Reference Price less regional transportation and storage;
- S.29(3)(5)(b) the Crown royalty share of gas and natural gas liquids will be amortized over a *12-month period*, beginning in January 1994. *(At the Minister's discretion, the Department may direct that the whole amount of an undischarged Crown royalty inventory is payable in one payment, and value it as if it is produced and subject to Crown royalty in January 1994.)*;
- a Crown royalty amount due that is less than $100,000 per product/facility/client will be charged to the client in full;
- S.29(4) the Department will calculate the monthly amount of the amortized payment by multiplying the volume/quantity of the amortized gas or natural gas liquid by the price that would apply if the same volume/quantity were subject to Crown royalty in the same month;
- S.29(5)(c) the Department will calculate and collect the value of the volume outstanding on account of undischarged Crown royalty sulphur inventory as though it is Crown royalty sulphur for 1994 *(at the same time and at the same price as sulphur produced and subject to Crown royalty in 1994); and*
- there will be no reduction for Crown share of cost allowances (Gas Cost Allowance is deemed to have been paid on all volumes in inventory).

The Department will carry out an adjusting process following the close-out of the 1993 gas royalty business. This will accommodate amendments and adjustments to pre-1994 records, which may have an impact on undischarged Crown royalty inventory liability. The adjustments will be implemented on a go-forward basis.

The amortization debit for undischarged Crown royalty liability will be reported on the *monthly invoice.* No interest will be charged or paid on the Crown royalty inventory settlement transaction and on subsequent adjustments to the Crown royalty inventory volumes.

18.4 Establishing Commercial Storage Scheme Opening Balances

Facility Operators of *commercial storage schemes* are responsible to report the opening gas balance for each scheme at January 1, 1994 on the Owner Activity Statement for January 1994. The Department will include that opening balance in its records of the volume and quantity of gas for each commercial storage scheme, subject to subsequent Departmental audit.

The business rules relating to commercial storage schemes are described in *Section 5.3.2.*

18.5 Estimating and Paying Crown Royalty Effective January 1994

18.5.1 Deposit in Lieu of Monthly Gas Royalty Estimate

The pre-1994 practice of paying estimated Crown royalty due one month following each production month, and adjusting that estimate at the two-month and three-month intervals, is replaced by a Crown royalty deposit process. The deposit process eliminates monthly debiting and crediting of estimates and adjustments, as well as the interest costs that were associated with the pre-1994 estimating process.

A detailed description of the business rules for the monthly deposit process is provided in *Section 9.4.*

18.5.2 Monthly Payments Pending Completion of Automated Systems

In order that the petroleum and natural gas industry and the Department might realize the benefits of the simplified natural gas royalty administration at the earliest possible date, industry and the Department agreed that the new natural gas royalty business rules will be implemented effective January 1, 1994. However, the automated systems required to fully implement the new business rules have not been completely developed. Therefore, a procedure for systematically determining an interim *estimated Crown royalty payment* is required until the automated system is fully implemented.

The *estimated Crown royalty payment* for a royalty client for a production month is calculated as:

(total Crown natural gas royalty remittances due (G2) for the royalty client
during the period January through December 1993
...divided by...
(12)
...multiplied by...
Provincial Price Factor for the production month

The *Provincial Price Factor* for a production month is calculated as:

Gas Reference Price for the production month
...divided by...
weighted average of monthly Alberta Average Market Prices for 1993 ($1.59/GJ)
(weighted by monthly Crown royalty quantity of raw gas, residue gas and ethane)

The Department will calculate the *Provincial Price Factor* for each production month and publish it in an *Information Bulletin.*

The Department will advise individual royalty clients of their total *"G2" Crown natural gas royalty remittances during 1993* in the month of January 1994.

If a royalty client disposes of or acquires properties and wishes to adjust his *estimated Crown royalty payment* to reflect that transaction, the royalty client may do so by:

- entering into an agreement with the royalty client(s) that acquired the subject properties; *and*
- notifying the Department in writing of the agreement, the parties to the agreement and the properties involved, and the *estimated Crown natural gas royalty* to be transferred from the disposing royalty client to the acquiring royalty client(s).

If a royalty client wishes to pay his monthly *estimated Crown royalty* using an actual calculation of his Crown natural gas royalty payable, he must apply in writing to the Team Leader, Client Services, describing the method he proposes to employ. If the Department approves the proposed method, the royalty client will be advised in writing that the proposed method may be used.

Royalty clients are responsible to report their *estimated Crown royalty* using the *(pre-1994) G2 form or "direct deposit,"* and remit payment (*Refer to Section 25.2*) on or before the last day of the third month following the production month to which the payment relates. The first payment for 1994 will be the April payment for the January production month. The Department will invoice Crown natural gas royalty to each royalty client in the month the automated systems become operational.

18.5.3 Interest on Estimated Crown Royalty

The Department will charge or credit interest monthly, on the difference between the estimated royalty paid by a royalty client and the actual royalty calculated by the Department from the royalty due date of the production month to the cash settlement date. *This is separate from any interest that may be charged for late payments.*

Interest that is receivable or payable by the Department will be calculated at the prime lending rate charged by the Alberta Treasury Branch on the first day of the month for which the interest is being calculated, *plus 1%*.

NOTE: THIS SECTION APPLIES ONLY FOR THE PERIOD THAT THE CROWN ROYALTY IS SUBMITTED ON AN ESTIMATE BASIS. (REFER TO SECTION 9.5 FOR THE PROCEDURE AFTER THE AUTOMATED SYSTEM IS IMPLEMENTED.

19. Reporting Overview

19.1 Forms Submitted by Industry to the Department

Exemptions, Waivers and Other Royalty Reductions

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
PW1	Monthly Statement of Proprietary Gas – Royalty Waived	Royalty Client	Monthly	NOTE 3
595	Sulphur Emission Control Assistance Program (SECAP) Application	Facility Operator	Annually	June 30

Volumetric Reporting of Mineral Activity

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
RMF1	Consolidated Single Well Group Setup/Change	Facility Operator	As Required	NOTE 1A
RMF2	Reassignment of Volumes Setup/Change	Royalty Client	As Required	NOTE 1B
RMF3	Single Well/Injection Scheme Setup/Change	Facility Operator	As Required	NOTE 1A
OAS	Owner Activity Statement	Facility Operator	Monthly	NOTE 2 & 8

Valuing Raw Gas, Residue Gas and Ethane

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
VA1	Election for Gas Valuation	Royalty Client	Once Only	NOTE 4
VA2	Corporate Average Price Calculation – Gas	Royalty Client	Annually	April 15
GR1	Application to Grandfather Co-generation or Other Long-Term Contracts	Royalty Client	Once Only	NOTE 5
GR2	Annual Statement of Grandfathered Contract Sales	Royalty Client	Annually	March 31

Valuing Gas Products

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
NGL1	NGL Valuation and Transportation	Designated Purchasers	Monthly	NOTE 7
NGL2	Storage Costs	Designated Storers	Annually	NOTE 9
VA3	Annual Corporate Average Price Calculation - Sulphur	Royalty Client	Annually	April 15
VA4	Monthly Corporate Average Price Calculation – Sulphur	Royalty Client	Monthly	NOTE 2

Alberta's Royalty Share of Allowable Costs

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
AC1	Facility Cost Centre Setup/Change	Facility Cost Centre Operator	As Required	NOTE 6
AC2-V1	Allowable Costs – Capital Costs 1994, 1995 and 1996	Facility Cost Centre Operator	Annually	April 15
AC2-V2	Allowable Costs – Capital Costs 1997 Onwards	Facility Cost Centre Operator	Annually	April 15
AC3	Allowable Costs – Capital Reallocations	Royalty Client	Annually	May 15
AC4	Allowable Costs – Operating Costs	Facility Cost Centre Operator	Annually	March 31
AC5-V1	Allowable Costs – Custom Processing Fees Paid 1994, 1995 and 1996	Royalty Client	Annually	May 15
AC5-V2	Allowable Costs – Custom Processing Fees Paid 1997 Onwards	Royalty Client	Annually	May 15

Miscellaneous Forms

FORM	FORM NAME	SUBMITTED BY	FREQUENCY	TIMING
AC10	Application for Plant Type Code and Transportation Region Code	EUB Facility Operator	As Required	NOTE 10
OC1	Facility Operator Change	EUB Facility Operator	As Required	NOTE 11
ICCI	Invoice Consolidation Concurrence Form	Facility Cost Centre Operator	As Required	NOTE 12
CPAF	Custom Processing Adjustment Factor	Facility Cost Centre Operator	As Required	NOTE 13
	Request for Refund	Royalty Client	As Required	
	Vendor Maintenance Request	Royalty Client	As Required	
OFSG	Otherwise Flared Solution Gas	Battery Operator	As Required	
	Gas Royalty Registry Update	Royalty Client	As Required	

Note: These forms are in Appendix P.

NOTES:

NOTE 1A- LAST DAY OF THE MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 1B LAST DAY OF THE THIRD MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 2 - 15TH DAY OF THE SECOND MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 3 - THE PW1 IS DUE ON THE LAST DAY OF THE MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 4 - A VA1 FORM WAS DUE JUNE 15, 1994 AND FOR A NEW ROYALTY CLIENT, THE 15TH DAY OF THE SECOND MONTH FOLLOWING THE PRODUCTION MONTH REPORTED ON OAS OR RMF2 FORM. THE VA1 FORM IS ALSO USED TO CHANGE THE ELECTION FROM CAP TO REFERENCE PRICE.
NOTE 5 - A GR1 FORM WAS DUE ON JUNE 15, 1994 (THERE IS NO FURTHER RIGHT TO ELECT).
NOTE 6 - AN AC1 FORM FOR A NEW FACILITY COST CENTRE IS DUE ON MAR. 1 FOLLOWING THE END OF THE PRODUCTION YEAR TO WHICH IT RELATES. AN AC1 OPERATOR CHANGE MUST BE SUBMITTED BY THE LAST DAY OF THE MONTH FOLLOWING THE MONTH IN WHICH AN OPERATOR CHANGE OCCURS.
NOTE 7 - 10TH DAY OF THE SECOND MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 8 - THE OAS MUST BE SUBMITTED BY THE PRIMARY FACILITY OPERATOR TO THE OWNERS AND CASCADE FACILITY OPERATORS ON OR BEFORE THE 25TH DAY OF THE MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 9 - 15TH DAY OF THE SECOND MONTH FOLLOWING THE PRODUCTION YEAR. (1994 only)
NOTE 10 - THIS FORM MUST BE SUBMITTED TO ESTABLISH OR CHANGE A PLANT TYPE CODE AND TRANSPORTATION REGION CODE, BEFORE COMMENCEMENT OF PRODUCTION.
NOTE 11 - THIS FORM MUST BE SUBMITTED IMMEDIATELY AFTER A CHANGE IN THE EUB FACILITYOPERATOR.
NOTE 12 - THIS FORM MUST BE SUBMITTED TO REGISTER A CONSOLIDATION WITHIN 30 DAYS OF THE EFFECTIVE BILLING PERIOD
NOTE 13 - CPAF FORM MUST BE SUBMITTED IMMEDIATELY AFTER A CPAF PERCENTAGE CHANGES. (VALID FOR PRODUCTION YEARS 1994, 1995 AND 1996. FROM 1997 ONWARDS, AC2-V2 FORM INCORPORATES CPAF CALCULATIONS.)
NOTE 14 - ON OR BEFORE THE 15TH DAY OF THE THIRD MONTH FOLLOWING THE PRODUCTION MONTH.
NOTE 15 - ON OR BEFORE THE LAST DAY OF THE SECOND MONTH FOLLOWING THE PRODUCTION MONTH

19.2 Reports Provided to Royalty Clients by the Department

Gas Royalty Statement/Invoice Package

PAGE	REPORT NAME	SUBMITTED BY	FREQUENCY	TIMING
25-7	Statement of Account	Department	Monthly	Note 14 Above
25-8	Invoice	Department	Monthly	Note 15 Above
25-17	Billing Period Detail:			
25-17	Prior Period Charges	Department	Monthly	Note 15 Above
25-18	Production Year Detail	Department	Monthly	Note 15 Above
25-22	Current Period Charges	Department	Monthly	Note 15 Above
25-20	Crown Royalty Summary	Department	Monthly	Note 15 Above
25-27	Crown Royalty Detail Calculation	Department	Monthly	Note 15 Above
25-33	Crown Royalty Detail Volumetric	Department	Monthly	Note 15 Above

19.3 Reporting Cycle for a Production Month

On the **25th day of the month** following the production month:

- all OAS documents for the production month must be received by the owners mentioned on the OAS documents and by the cascade facility operators.

On the **last day of the month** following the production month, the following forms must be received by the Department:

- all *required* RMF1 forms for the production month;
- all *required* RMF3 forms for the production month;
- all PW1 forms for the production month; *and*
- all AC1 forms to register Facility Cost Centre Operator changes

On the **10th day of the second month** following the production month:

- all NGL1 forms for the production month must be received by the Department.

On the **15th day of the second month** following the production month:

- all OAS document for the production month must be received by the Department;
- all VA4 forms for the monthly Sulphur Corporate Average Price Calculation must be received by the Department;
- the Department will publish the following *Crown royalty valuation* variables:
    - Gas Reference Price, Propane Reference Price, Butane Reference Price and Pentanes-plus Reference Price for the production month,
    - regional Transportation Allowances and Storage Allowances for the production month, *and*
    - natural gas liquids Fractionation Allowances for the production month, and
- the Department will publish the following *Crown royalty share* variables;
    - Gas Par Price for the production month,
    - Old Gas and New Gas Select Prices and royalty rates for the production month,
    - Pentanes Par Price and Pentanes Select Price for the production month, *and*
    - Old Pentanes and New Pentanes royalty rates for the production month.

On or before **the last day of the second month** following the end of a production month:

- all Invoices must be provided to royalty clients; *and*
- all Crown Royalty Detail Statements must be provided to royalty clients.

On or before **the 15th day of the third month** following the end of a production month:

- all Statements of Account must be provided to royalty clients.

On or before **the last day of the third month** following the end of a production month:

- Crown natural gas royalty invoices must be paid by royalty clients; and
- all required RMF2 forms for the production month must be received by the Department.

19.4 Reporting Cycle for a Production Year

On **the 15th day of the second month** following the year of production:

- all NGL2 forms for the production year (1994 only) must be received by the Department.

On **March 1** following the end of a production year, the Department must receive:

- all AC1 forms for Facilities that commenced operation during the production year.

On **March 31** following the end of a production year, the Department must receive:

- all GR2 forms for the production year; *and*
- all AC4 forms for the production year.

On **April 15** following the end of a production year, the Department must receive:

- all VA2 forms for the production year;
- all VA3 forms for the production year; *and*
- all AC2 forms for the production year.

On **May 15** following the end of a production year, the Department must receive:

- all AC3 forms for the production year; *and*
- all AC5 forms for the production year.

On **May 31** following the end of a production year:

- the Department will publish Unit Operating Cost Rates, full and delayered.

On **June 30** following the end of a production year, the Department must receive:

- all SECAP (595) forms for the production year.

19.5 Reporting Standards and Styles

The standards and styles described in the following subsections are required in all forms used by the petroleum and natural gas industry to report to the Department.

19.5.1 Volumetric Measurement and Conversion to Gigajoules (GJ)

A.R. 351/93
S.4(1)(3)

The following standards apply to all volumetric measurement and to required conversions of volume to heat content:

- *cubic metre of gas* means the volume of natural gas or residue gas which, when dry and at standard temperature and under standard pressure, will fill a space of one cubic metre;
- *gross or higher heating value* means the total **joules*** obtained by the complete combustion of one cubic metre of natural gas or residue gas and air under conditions where:
  - the combination reaction is at constant standard pressure,
  - the gas, including acid gas components, is free of all water vapour,
  - the temperature of the gas, air and products of combustion are at standard temperature, *and*
  - all water formed by the combustion reaction is condensed to a liquid state;

**For definition, please see Appendix N - Glossary.*

- *heat content* means the total amount of heat contained in a gas stream, including sensible heat and latent heat of condensation;
- *standard pressure* means the absolute pressure of 101.325 kilopascals;
- *standard temperature* means 15 degrees Celsius (15°C); *and*
- *volumes of natural gas, residue gas or ethane*, in gaseous form *(gas)*, shall be converted to *gigajoules* by multiplying the volume of the gas by the gross or higher heating value of the gas.

S.4(2) The following standards apply to all volumetric or heating value reporting:

- *volumes of natural gas or residue gas* shall be expressed in thousands of cubic metres (10^3m^3) to the nearest tenth of a thousand cubic metres *(e.g., 99.9* 10^3m^3*)*;
- *heating value of natural gas or residue gas* shall be expressed in megajoules per cubic metre (MJ/m^3) to the nearest hundredth of a megajoule per cubic metre *(e.g., 37.88* MJ/m^3*)*;
- *quantities of natural gas or residue gas* shall be expressed as heat content in gigajoules (GJ) to the nearest whole gigajoule *(e.g., 136.6 GJ and 137.2 GJ should be reported as 137 GJ)*;
- *volumes of ethane, propane, butane, pentanes-plus and field condensate* shall be expressed in cubic metres (m^3) to the nearest tenth of a cubic metre *(e.g., 66.9* m^3*)*; *and*
- *quantities of sulphur* shall be expressed in tonnes (t) to the nearest tenth of a tonne *(e.g., 34.9t)*.

19.5.2 Monetary Values

All monetary values required in forms provided to the Department must be in Canadian dollars, unless otherwise specified by the Department in its instructions regarding completion of the form.

The mathematical accuracy required for reporting monetary values to the Department is as follows:

- *unit price of gas* shall be expressed in dollars and cents to the nearest tenth of a cent per gigajoule (e.g., $2.359 per GJ); the Department will round to the nearest cent;
- *unit price of natural gas liquids and sulphur* shall be expressed in dollars and cents to the nearest cent per unit *(e.g., $132.15 per* m^3 *of pentanes-plus)*;
- *dollar amounts on the AC2, AC4 and AC5 forms* shall be expressed to the nearest dollar *(e.g., $1,325,499)*; *and*
- *dollar amounts on all other required forms* shall be expressed in dollars and cents to the nearest cent *(e.g., $15,329.99)*.

19.5.3 Negative Values

Negative values, whether volumes, heat content or monetary, will be indicated by a leading negative sign *(e.g., -1,375.1* m^3 refers to a negative volume of 1,375.1 m^3).

19.5.4 Dates

All dates required in forms provided to the Department are in numeric format:

- *year* is a four-digit number *(e.g., 1994)*;
- *month* is a two-digit number assigned to each month progressively from January *(month "01")* through to December *(month "12")*;
- *day* is a two digit number that is the calendar day *(e.g., 01...25...)*

All dates required in forms provided to the Department are expressed in *year-month-day* sequence, with each part separated by a decimal point. In some instances *(e.g., production month)* the requirement is for year and month only *(e.g., 1994.03 refers to the production month of March 1994)*. In other instances *(e.g., date prepared)*, the requirement is for year, month and day *(e.g., 1994.07.25 refers to the "date prepared" as July 25, 1994)*.

19.5.5 Dates on Amended Forms

The "*Date Prepared" (or "Filing Date")* entered in an *amended form* must be subsequent to the "Date Prepared" entered in the form which the *amended form* replaces.

Please see Section 10.5 for close-out dates of operation for a production year.

19.5.6 Due Date of Forms

The due dates of forms will be adhered to without exception unless otherwise agreed to by the Department. Penalties will apply if the forms are not received by the due dates. If the due dates fall on a weekend or a holiday, the next business day will apply. *(Refer to Section 9.3 for Invoice Due Dates.)*

19.5.7 Time

Time is recorded for Electronic Data Interchange (EDI) tools and techniques using the 24-hour clock. The 24-hour clock begins counting from midnight *(e.g., 5 minutes after midnight is recorded as 00:05, 11:30 a.m. is recorded as 11:30, 3:30 p.m. is recorded as 15:30 and midnight is recorded as 24:00)*.

19.5.8 Telephone Numbers

Where telephone numbers are required on a form provided to the Department, the telephone number is a 10-digit number that includes *area code-calling station-sequence number (e.g., 780-427-2962 is the full telephone number of the Gas Royalty Operations Help Desk)*.

19.5.9 Client IDs

When completing required reporting forms, the royalty clients who have a three digit client ID should add a preface zero (0) to their client ID. For example: XX1 must be written as 0XX1.

If royalty clients have both, a four digit ID and a seven digit ID, the four digit ID must be used.

20. Exemptions, Waivers and Other Royalty Reductions

20.1 Preparing an Application for Proprietary Gas Consumed

PW1 FORM - MONTHLY STATEMENT OF PROPRIETARY GAS - ROYALTY WAIVED

PURPOSE

Royalty clients must use the PW1 form to apply for a *royalty credit* on proprietary gas consumed in approved commercial oil sands schemes and experimental oil projects for each production month in which a claim is to be made.

A description of the business rules relating to eligibility for Crown royalty waiver is provided in *Section 5.2.3 and Section 20.3.*

TIMING

For approved commercial oil sands schemes and experimental oil projects, a completed PW1 form must be received by the Client Services Help Desk on or before the last day of the month following the production month to which the report applies, unless specified otherwise in the Crown Agreement.

CONSEQUENCES OF NON-COMPLIANCE

If a PW1 form is not filed by the due date, it will be processed in the month in which it is received, and the royalty credit will be applied on a go-forward basis. Application for a retroactive adjustment to a production period will not be approved.

AMENDING A MONTHLY STATEMENT OF PROPRIETARY GAS - ROYALTY WAIVED

An amended PW1 form must be completed in full just as with an initial PW1 form.

PW1 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number that identifies the royalty client submitting the form.

1.2 **CLIENT NAME** - The full name of the royalty client whose code appears in *field 1.1.*

1.3 **PRODUCTION YEAR/MONTH** - The numeric year and month of the production month to which the report relates.

1.4 **DATE PREPARED** - The numeric year, month and day on which the PW1 form is prepared.

1.5 **CONTACT PERSON** - The name of the person whom the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number and area code of the contact person.

PART 2: PROPRIETARY GAS DATA

2.1 **PROJECT NAME** - The project/scheme name assigned by the Department to the commercial oil sands scheme or experimental oil project for which a waiver is claimed.

2.2 **VOLUME OF GAS CONSUMED** - The volume, in 10^3m^3, of gas consumed in the project as identified in *field 2.1* during the production month.

2.3 **HEAT CONTENT OF GAS CONSUMED** - The quantity, in gigajoules (GJ), of gas consumed, as reported in *field 2.2*.

2.4 **DESIGNATED SOURCE** - The designated source of production. This production source must identify the EUB facility and the Stream ID (e.g., *Single Well, Well Group, Unit, and/or Injection Scheme*).

PART 3: CERTIFICATION

3.1 **AUTHORIZED SIGNATURE** - The signature of the person who is authorized to sign for the royalty client (signing officer) and who is responsible for the information submitted.

3.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized officer whose signature appears in *field 3.1*.

3.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.1*.

3.4 **DATE** - The date on which the authorized signing officer signed the PW1 submission.

20.2 Deep Gas Royalty Holiday

Prior to March 1, 1994, applications for relief under the Deep Gas Royalty Holiday Program were to be received by the Department within six months of the finished drilling date of the well event.

Effective March 1, 1994 clients are no longer required to file an application for DGRHP benefits. This change in procedures applies only to wells that have a finished drill date (FDD) after February 28, 1994.

On a monthly basis:

- Gas Operations will access EUB data to identify all wells with a FDD after February 28, 1994 with initial production of natural gas that satisfy the eligibility criteria for the DGRHP as stipulated under Schedule 6 of the Natural Gas Royalty Regulations, AR351/93.
- Gas Operations will inform the operator and the licensee by letter of the well's eligibility, the deep gas holiday benefit amount and other pertinent data.

The Department will provide each client with a statement showing the well's holiday amount and the client's holiday amount taken. The statement is included with the monthly Invoice Package.

The maximum benefit payable under the program is calculated based on the qualifying interval of the well event, as follows:

Qualifying Interval Metres	Cumulative Value ($000)	Incremental Value $/Metre
2500	0	
		1000
3000	500	
		1000
3500	1000	
		1000
4000	1500	
		1300
4500	2150	
		1300
5000	2800	
		1600
5500	3600	

- *For post-1993 period, the weighted Provincial Average Gross-Up Factor will be applied to the above amount to determine the eligible holiday benefits. Refer to Section 20.2.1, second table, for the calculation of this benefit.*

NOTE: THE QUALIFYING INTERVAL IS THE DEPTH OF THE DRILLED OR DEEPENED PORTION OF THE WELL EVENT BELOW 2,500M TO THE BASE OF THE DEEPEST NATURAL GAS-BEARING INTERVAL PRODUCING IN PAYING QUANTITIES.

A more complete description of the Deep Gas Royalty Holiday Program is provided in the *Guidelines for Crude Oil Royalty Holiday Program, Exploratory Gas Well Incentive Program, and Deep Gas Royalty Holiday Program.*

20.2.1 Calculation of Benefits — 1994 and Onwards

Prior to January 1, 1994, for Crown royalty holidays subject to a maximum benefit per well event, the maximum benefit payable and the monthly benefit paid under a Crown gas royalty holiday program were calculated in net dollars (value of the Crown royalty share of production minus the Crown Share of Cost Allowances). The changes made to how the Crown's share of cost allowances are paid by the Crown take priority over the calculation of net Crown royalty at the well event level in 1994 and later. Accordingly, the maximum benefits payable and monthly benefits paid will be calculated at the **gross Crown royalty*** level (value of the Crown royalty share of production).

The remaining portion of the maximum benefit payable for each well event that qualified in 1993 or earlier will be calculated as:

Remaining net Crown royalty holiday benefit *(at December 31, 1993)*
...multiplied by...
([1991, 1992 and 1993 calculated gross Crown royalty for the well event]
...divided by...
[1991, 1992 and 1993 net Crown royalty waived for the well event])

The maximum benefit payable will be reduced each month by the gross Crown royalty value of production from the eligible well event.

All working interest owners' remaining balances for a holiday well event as at December 31, 1993 were summed up to create a total gross balance for the holiday well event at January 1, 1994. Monthly, the holiday balance will be reduced via the OAS document received in that month for each owner. The Department will prorate the remaining balance in the month in which the well event reaches its holiday limit on the OAS document filed for that holiday well event. Holiday benefits received or not received at the time the well event reaches the royalty holiday limit must be resolved between/among the working interest owners for the holiday well.

For **royalty holiday wells*** with less than 3 years of data on December 31, 1993, or for those holiday wells that became effective after December 31, 1993, the Provincial Weighted Average Gross-Up Factor will be used, unless specified otherwise by the Minister. This factor is subject to an independent audit by the industry.

The Crown royalty exemption for well events under such category will be calculated as follows:

Benefit payable based on the qualifying interval of the well event *(table)*
...multiplied by...
([1991, 1992 and 1993 calculated gross Crown royalty for all royalty holiday well events]
...divided by...
[1991, 1992 and 1993 net Crown royalty waived for all royalty holiday well events])

The Department will distribute Royalty Exemption Statements annually or when the holiday expires or when the dollar cap is reached. *(Refer to Section 25.7.8 for an example of Royalty Exemption Statement.)*

****For definition, please see Appendix N - Glossary.***

20.2.2 Application for Deep Gas Royalty Holiday

The Deep Gas Royalty Holiday program applies to any gas well spudded or deepened on or after June 1,1985:

- into a producing zone, the top of which is deeper than 2,500 m; *and*
- within a drilling spacing unit that is wholly outside the pool boundaries designated by the EUB at June 1, 1985. Refer to *Section 5.1.1* for additional information.

A more complete description of the *Deep Gas Royalty Holiday Program* is provided in the *"Guidelines for Crude Oil Royalty Holiday Program, Exploratory Gas Well Incentive Program, and Deep Gas Royalty Holiday Program." (This can be obtained by phoning the Client Services Help Desk at (780) 427-2962 or Alberta Toll Free: 1-310-0000).*

20.3 Gas Consumed in Oil Sands Schemes and Experimental Oil Projects

A description of the business rules relating to eligibility for Crown royalty waiver is provided in *Section 5.2.3.*

Where a waiver of Crown royalty share exists, each royalty client who is eligible to claim the waiver must submit a PW1 form to the Department for each production month in which a claim is made, identifying the quantities consumed as fuel. The Department must receive the report on or before the last day of the month following the production month related to the report unless specified otherwise in the Crown Agreement. *(Refer to Section 20.1)*

The Department will calculate the quantity of the Crown royalty waiver using designated source vintage and Crown interest. The Crown will value it using the valuation price elected by the royalty client (i.e., CAP or Reference Price).

The Department will calculate the amount of the waiver, which will be reduced by the Unit Operating Cost Rate (UOCR) at the source facility. The annual Crown share of **Capital Cost Allowance*** and Custom Processing Cost Allowance for a royalty client who receives a waiver will be adjusted through the Corporate Effective Royalty Rate. *(Refer to Section 16.8.2)*

20.4 Injected Gas and Gas Products

Injection Schemes are registered using the ***Single Well/Injection Scheme Setup/Change (RMF3)*** form. The procedures for registering an Injection Scheme are described in *Section 21.3.*

The Department calculates injection credits based on information taken from OAS reports filed by Facility Operators. The principles, under which entitlement to injection credits are determined and calculated, are described in *Section 5.3.1.*

The Department will calculate the injection credit for a royalty client for a production month by:

- Determining the quantity of the Crown's royalty share of gas and gas products delivered to the Injection Facility by the royalty client for the purpose of injection into an Injection Scheme. The Crown's royalty share will be determined as though the gas and gas products have been produced from the same Injection Scheme in the same month.
- Valuing the Crown's royalty share at the price that would have been used to determined the amount payable to the Crown by the royalty client if the gas or gas product had been recovered and also subject to the payment of Crown royalty in the same month.

Note: (1) INJECTION CREDIT DOES NOT APPLY TO VOLUMES DELIVERED TO THE INJECTION FACILITY TO BE USED FOR FUEL, WHERE GAS OR A GAS PRODUCT IS NOT AN INJECTANT
(2) INJECTION CREDIT VALUE IS NOT REDUCED BY OPERATING COSTS.

****For definition, please see Appendix N – Glossary.***

20.4.1 New Gas and New Pentanes-Plus Status

There is no monthly or annual reporting requirement unique to New Gas and New Pentanes-plus and, in most cases, there is no unique application process to establish New Gas and New Pentanes-plus status. *(Refer to Sections 4.9.3 and 4.11.2.)*

The process through which *"New"* status is determined and communicated by the Department is:

- the operator of the well event completes and submits the required well information reports *(S1 and S4)* to EUB, who then advises the Department;
- the Department classifies the well event and advises the operator of the facility *(Facility Operator)* from which the well event receives gas and gas product allocations; *and*
- the Facility Operator is responsible for notifying all participants in the well event of the *New/Old* status of the well event.

Where a well event is part of a *multiple production entity,* the operator of the well event must apply to the Department to establish the *vintage* of the gas and pentanes-plus produced and recovered from the well event or multiple production entity. An application for *"New"* status must be submitted in writing to the Director of Petroleum Royalty and Incentives, and must include the full name and description of the multiple production entity and the requested effective date of the status. There is no official form required for such an application.

The *"New" or "Old"* status *(vintage)* of the gas or pentanes-plus produced and recovered from a well event applies only to the Crown interest share.

Effective January 1, 1994, the *vintage* of pentanes-plus is the same as the *vintage* of the gas with which it is produced and from which it is recovered, unless otherwise determined by the Minister.

20.5 Enhanced Oil Recovery (EOR) Scheme* - Recovery of Cost Allowances

Where gas and gas products are injected into an EOR scheme, approved under the **Enhanced Recovery*** of Oil Royalty Reduction Regulation, the Crown will recover operating costs previously deducted from Crown royalty as follows:

- the Crown share of the operating costs to be recovered will be calculated on the lesser of the royalty client's proprietary volumes produced versus those injected into the same EOR scheme in the same month;
- this lesser of the two volumes is considered as indigenous volumes;
- the operating cost facility will be the location facility on the OAS document that processed the production volumes. This facility's UOCR will be used in the calculation to recover the costs;
- the EOR scheme **stream ID*** will be the same for both OAS records (the processing plant and injection facility) to determine the lesser of the two quantities;
- if the stream ID occurs on several OAS documents the indigenous volumes will be determined from the total of all OAS document combined; *and*
- where more than one processing facility is involved, the volumes will be prorated to each facility and the UOCR of each facility will be applied to the prorated volumes.

Capital Cost Allowances and Custom Processing Cost Allowances on the total indigenous quantity will be recovered through an annual adjustment at the Client/EUB facility level where the indigenous quantities are processed. This adjustment will determine the indigenous volumes based on the total annual injection and production volumes. (For more detail, refer to *1994 Conventional Enhanced Oil Recovery Royalty Guidelines.)*

****For definition, please see Appendix N - Glossary.***

20.6 Preparing a SECAP Application

FORM 595 - SULPHUR EMISSION CONTROL ASSISTANCE PROGRAM APPLICATION

PURPOSE

Facility Operators must use the *595* form to apply for eligibility under the Sulphur Emission Control Assistance Program *(SECAP)* and to report annual eligible operating expenses for a year.

A description of the eligibility requirements for SECAP is provided in *Section 8.2 and Section 17.4.*

TIMING

To apply for eligibility for SECAP a *595* form must be received by the Client Services Help Desk, within six months following the first production year to which the application applies.

To apply for annual eligible operating expenses a *595* form must be received by the Team Leader, Client Services Help Desk, within six months following the production year to which the application applies.

FORM 595 - COMPLETION INSTRUCTIONS

PART 1: FACILITY IDENTIFICATION

1.1 **PLANT NAME** - The name assigned by EUB to the gas plant that is the subject of the application.

1.2 **EUB FACILITY CODE**- The EUB code assigned to the facility described in *field 1.1.*

1.3 **PLANT OPERATOR** - The full name of the person who is the operator of the facility that is the subject of the application.

1.4 **EUB APPROVAL NO.** - The five-character number assigned by EUB to the approved sulphur processing facility.

1.5 **EUB APPROVAL DATE** - The date of approval of the gas processing plant/process by EUB.

PART 2: ELIGIBLE CAPITAL COSTS

(INDICATE YEAR CAPITAL COSTS WERE INCURRED IN)

2.1 **APPROVED EQUIPMENT** - The description of each item of equipment included in the application.

2.2 **COST**- The actual cost of each item of equipment identified in *field 2.1.*

2.3 **TOTAL ELIGIBLE CAPITAL COSTS** - The sum of all of the costs recorded in *field 2.2.*

PART 3: ELIGIBLE OPERATING EXPENSES

(INDICATE YEAR OPERATING EXPENSES WERE INCURRED IN)

3.1 **LABOUR** - The description and cost for labour included in Operating Expenses.

3.2 **MATERIALS**- The description and cost for materials included in Operating Expenses.

3.3 **PARTS/SUPPLIES-** The description and cost for other parts and supplies included in Operating Expenses.

3.4 **TOTAL ELIGIBLE OPERATING EXPENSES** - The sum of all of the costs recorded in *fields 3.1, 3.2 and 3.3.*

PART 4: CALCULATION OF CREDIT

4.1 **ELIGIBLE CAPITAL COSTS** - The TOTAL ELIGIBLE CAPITAL COSTS as recorded in *field 2.3.*

4.2 **CAPITAL COST CREDIT** - ELIGIBLE CAPITAL COSTS as recorded in *field 4.1 ...multiplied by...50%.*

4.3 **ELIGIBLE OPERATING EXPENSES** - The TOTAL ELIGIBLE OPERATING EXPENSES as recorded in *field 3.4.*

4.4 **OPERATING EXPENSE CREDIT** - ELIGIBLE OPERATING EXPENSES as recorded in *field 4.3 ...multiplied by... 50%.*

4.5 **TOTAL** - The sum of the amounts recorded in *fields 4.2 and 4.4.*

4.6 **NAME OF PARTICIPANT** - The name of each person who is a participant in the subject application.

4.7 **ROYALTY CLIENT ID** - The four-character EUB operator code or the seven-character royalty client ID number assigned by the Department to the participant(s) identified in *field 4.6.*

4.8 **PERCENTAGE OF CREDIT** - The percentage of the TOTAL CREDIT recorded in *field 4.5* that is assigned to each royalty client identified in *fields 4.6 and 4.7.*

4.9 **CREDIT** - The dollar amount of the TOTAL CREDIT that is assigned to each royalty client identified in *fields 4.6 and 4.7 (field 4.5 ...multiplied by... field 4.8 for each royalty client).*

PART 5: CERTIFICATION

5.1 **NAME** - The name of the authorized signing officer who is certifying the subject application.

5.2 **DATE** - The date on which the "595" application is signed.

5.3 **SIGNATURE OF AUTHORIZED COMPANY OFFICIAL** - The signature of the authorized signing officer whose name appears in *field 5.1.*

5.4 **NAME OF AUTHORIZED COMPANY OFFICIAL** - The full name of the authorized signing officer whose signature appears in *field 5.3.*

5.5 **TITLE** - The position title of the authorized signing officer whose signature appears in *field 5.3.*

21. Volumetric Reporting of Mineral Activity

21.1 Registering a Consolidated Single Well Group

RMF1 FORM - CONSOLIDATED SINGLE WELL GROUP SETUP/CHANGE

PURPOSE

Facility Operators must use the RMF1 form if they choose to register the initial setup of a *Well Group* with the Department, to change the makeup of an existing *Well Group* or to terminate an existing Well Group.

A description of the criteria that must be satisfied to establish a *Well Group* is provided in *Section 4.6.1.*

A description of the criteria that must be satisfied to establish an *Injection Scheme* is provided in *Section 4.6.1.*

NOTE: HOLIDAY WELLS MUST BE REPORTED AS SINGLE WELLS ON THE OAS DOCUMENT IN ORDER TO RECEIVE THE HOLIDAY BENEFITS.

TIMING

A completed RMF1 form to register the setup of a *Well Group*, to change the makeup of a *Well Group,* or to terminate a *Well Group* must be received by the Client Services Help Desk on or before the last day of the month following the production month to which the form applies.

CONSEQUENCES OF NON-COMPLIANCE

The RMF1 form will not be processed if a Facility Operator fails to satisfy the reporting requirements for registering a *Well Group*

NOTE: EFFECTIVE JANUARY 1999 ONWARDS, THE PENALTY OF $1000 PER MONTH OR PART OF A MONTH, FOR FAILURE TO FILE THE RMF1 BY ITS DUE DATE IS REMOVED.

AMENDING A WELL GROUP SETUP/CHANGE

An amendment to the RMF1 form must be a single line amendment and not a full form replacement; however, Part 1 must always be completed in full.

RMF1 FORM – COMPLETION INSTRUCTIONS

PART 1: CLIENT INFORMATION

1.1 **OPERATOR ID** - The four-character EUB operator code that identifies the Facility Operator submitting the form.

1.2 **OPERATOR NAME** - The full name of the Facility Operator whose code appears in *field 1.1.*

1.3 **DATE PREPARED** - The numeric year, month and day on which the RMF1 form is prepared.

1.4 **CONTACT PERSON** - The name of the person whom the Department can contact concerning information on the form.

1.5 **TELEPHONE** - The telephone number, including area code, of the contact person.

PART 2: WELL GROUP INFORMATION

2.1 **WELL GROUP ID** - The identifier assigned by the Department to the *Well Group* that is the subject of the report:

- if the RMF1 is submitted for an initial setup, leave this field blank. The proposed *Well Group* will not have a Department-assigned ID; *or*
- if the RMF1 is submitted to change or terminate an existing *Well Group,* enter the WELL GROUP ID assigned by the Department.

2.2 **UPDATE CODE** - Enter a "1" in this field if the form is submitted to set up a *new Well Group,* or "2" if the form is submitted to change or terminate an existing *Well Group.*

2.3 **EFFECTIVE DATE** - The numeric year and month in which the setup is to become effective. The effective date will be the first day of that production month.

2.4 **TERMINATION DATE** - The numeric year and month in which the *Well Group* setup is to be terminated. The effective date of the termination will be the first day of that production month. If a Well Group is to be terminated from the original effective date, the termination date should be the same as the original effective date.

If a *Well Group* is terminated and no new *Well Group(s)* is set up in its place, the *well events* that were included in the terminated *Well Group* will become *Single Well Royalty Entities* by default. If that outcome is what is wanted, no additional filing is required.

PART 3: UNIQUE WELL IDs WITHIN A CONSOLIDATED SINGLE WELL GROUP

3.1 **UPDATE CODE** - Enter a "1" in this field to add a new well event to the *Well Group*, or a "2" to change or terminate an existing well event.

3.2 **UNIQUE WELL ID** - The **unique well identifier*** assigned by the EUB to the well event that is to be added, changed or terminated.

3.3 **EFFECTIVE DATE** - The numeric year and month in which the well event is to be added to the *Well Group.* The effective date will be the first day of that production month.

3.4 **TERMINATION DATE** - The numeric year and month in which the well event is to be terminated from the Well Group. The effective date will be the first day of that production month.

3.5 **PAGE___OF___** - The page number of each individual page followed by the total number of pages submitted for each *Well Group.*

NOTE: AN RMF1 CONTINUATION PAGE IS PROVIDED TO ACCOMMODATE LARGER WELL GROUPS. THE CONTINUATION PAGE INCLUDES ONLY THAT INFORMATION NOTED FOR PART 3 ABOVE. THE PROCEDURES FOR COMPLETING IT ARE THE SAME. PLEASE STATE, "CONTINUATION PAGES ARE ATTACHED", IN THE BOTTOM SPACE OF PART 3, IF APPLICABLE.

**For definition, please see Appendix N - Glossary.*

21.2 Preparing a Reassignment of Volume Setup/Change

RMF2 FORM - REASSIGNMENT OF VOLUMES SETUP/CHANGE
THIS FORM MUST BE FILED ONLY BY AN ASSIGNOR

PURPOSE

Royalty clients are to use the RMF2 form if they wish to reassign all or part of their OAS Crown and/or Freehold volumes of gas and gas products allocated to well events, well groups, units or injection schemes.

If the RMF2 form is to be processed retroactively, then the assignor must submit this request in writing to the Department.

A description of the business rules governing reassignment of volumes or acceptance of volumes is provided in *Section 4.8.*

TIMING

A completed RMF2 form must be received by the Client Services Help Desk on or before the last day of the third month following the production month to which the form applies.

CONSEQUENCES OF NON-COMPLIANCE

Reporting requirements for the RMF2 form include obtaining written concurrence from the assignor and all the assignees. Failure to obtain and submit the required concurrence constitutes failure to satisfy the reporting requirements. Concurrence is not required from the assignees if an assignor terminates the RMF2 assignment.

The RMF2 form will not be processed if a royalty client fails to satisfy the reporting requirements for reassignment of volumes.

NOTE: EFFECTIVE JANUARY 1999 ONWARDS, THE PENALTY OF $1000 PER MONTH OR PART OF A MONTH, FOR FAILURE TO FILE THE RMF2 BY ITS DUE DATE IS REMOVED.

AMENDING A REASSIGNMENT OF VOLUMES SETUP/CHANGE

An amended RMF2 form must be completed in full just as with an initial RMF2 form.

RMF2 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT INFORMATION

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number that identifies the royalty client submitting the form.

1.2 **CLIENT NAME** - The full name of the royalty client whose code appears in *field 1.1.*

1.3 **DATE PREPARED** - The numeric year, month and day on which the RMF2 form is prepared.

1.4 **CONTACT PERSON** - The name of the person whom the Department can contact concerning the information on the form.

1.5 **TELEPHONE** - The telephone number, including area code, of the contact person.

PART 2: CONCURRENCE

2.1 **CONCURRENCE IS ATTACHED** - Check this box to indicate that a written concurrence for each of the assignments recorded in PART 4 is attached to the RMF2.

NOTE: THE ROYALTY CLIENT WHO IS SUBMITTING THE RMF2 (I.E., THE ASSIGNOR) IS RESPONSIBLE FOR OBTAINING THE WRITTEN AND SIGNED CONCURRENCE FROM EACH ROYALTY CLIENT TO WHOM A VOLUME IS TO BE ASSIGNED.

FOR AMENDMENTS, A CONCURRENCE DOES NOT NEED TO BE REFILED FROM CLIENTS WHOSE PERCENTAGE OF THE ALLOCATED SHARE DOES NOT CHANGE. IF THE CLIENT WHO ORIGINALLY REASSIGNED THE VOLUMES HAS CHANGED, CONCURRENCE MUST BE RECEIVED FROM ALL CLIENTS.

PART 3: REASSIGNMENT OF VOLUMES FROM THE OWNER ACTIVITY STATEMENT

3.1 **STREAM ID** - Enter one of the following:

- the unique well identifier assigned by the EUB if the RMF2 is for a single well event; **or**
- the code assigned by the Department if the RMF2 is for a Well Group, a Unit or an Injection Scheme. For an Injection Scheme, enter the new five digit code.

The first four letters comprising the provincial code and stream ID type must be indicated before the identifier code as per the PRIDE standards.

3.2 **PRODUCT NAME** - The product name if the RMF2 is for a specific product type. Valid products are: Gas, Ethane, Propane, Butane, Pentanes-plus and Sulphur.

NOTE: IF THE RMF2 IS FOR ALL GAS AND GAS PRODUCTS, THIS FIELD IS LEFT BLANK.

3.3 **EFFECTIVE DATE** - The numeric year and month in which the reassignments recorded in PART 4 are to be effective. The effective date will be the first day of that production month.

3.4 **TERMINATION DATE** - The numeric year and month in which the reassignments recorded in PART 4 are to be terminated. The effective date of the termination will be the first day of that production month.

NOTE: WHERE VOLUMES HAVE BEEN REASSIGNED, THE ROYALTY CLIENT WHO ACCEPTS THOSE VOLUMES MAY NOT SUBSEQUENTLY REASSIGN IT. ONCE THE ROYALTY RESPONSIBILITY FOR A CLIENT HAS BEEN ESTABLISHED ON THE RMF2, THAT CLIENT MAY NOT FURTHER REASSIGN ALL OR A PORTION OF THEIR ROYALTY RESPONSIBILITY TO A DIFFERENT CLIENT. IF THERE IS A NEED TO DIVIDE THE VOLUMES FURTHER THAN WAS DONE ON THE ORIGINAL RMF2, THE ORIGINAL REASSIGNMENT MUST BE TERMINATED AND A NEW REASSIGNMENT CREATED WITH THE CONCURRENCE OF ALL THE AFFECTED ORIGINAL ROYALTY CLIENTS PLUS ANY NEW CLIENTS LISTED ON THE RMF2.

PART 4: REASSIGNMENT OF VOLUMES

4.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number that identifies the royalty client ***accepting*** the volumes assigned from the royalty client identified in *1.1 and 1.2 above.*

4.2 **CLIENT NAME** - The full name of the royalty client whose code appears in *field 4.1.*

4.3 **ALLOCATION SHARE %** - The percentage share of the volumes of the royalty client recorded in *fields 1.1 and 1.2*, which is accepted, by the royalty client recorded on *fields 4.1 and 4.2.*

NOTE: THE ROYALTY CLIENT WHO IS IDENTIFIED IN *FIELDS 1.1 AND 1.2* MUST ASSIGN 100% OF HIS VOLUMES IN THE WELL/WELL GROUP/UNIT/INJECTION SCHEME THAT IS THE SUBJECT OF THE REPORT. IF THE ROYALTY CLIENT WHO IS ASSIGNING VOLUMES WISHES TO RETAIN A PORTION OF THOSE VOLUMES, HE MUST RECORD THAT ACCEPTANCE IN *FIELDS 4.1, 4.2 AND 4.3.*

THE TOTAL OF THE VOLUMES ACCEPTED BY THE ROYALTY CLIENT(S) IDENTIFIED IN *FIELDS 4.1 AND 4.2* MUST EQUAL 100%.

21.3 Registering a Single Well or Injection Scheme

RMF3 FORM - SINGLE WELL/INJECTION SCHEME SETUP/CHANGE

PURPOSE

Facility Operators must use the RMF3 to register the initial setup, change the setup or terminate:

- a *Well (a single well event)* that has a Crown interest greater than 0% but less than 100%;
- a Non-Consolidated *Well Group* consisting of Joint Operating Agreements, Non-Unit Gas, Non-Unit Spacing, Non-Unit Oil (solution gas) and projects that have Crown interest of greater than 0% but less than 100%; *or*
- an Injection Scheme.

For the single well portion of the RMF3, the form is not required if all the working interest owners' **Crown percentage*** is the same as the well(s)'s Crown percentage.

A description of the business rules governing the responsibility to register a *Well/Well Group* is provided in *Section 4.6.1.*

A description of the business rules that must be satisfied to establish an *Injection Scheme* is provided in *Section 4.5.*

TIMING

A completed RMF3 form must be received by the Client Services Help Desk on or before the last day of the month following the production month to which the form applies.

CONSEQUENCES OF NON-COMPLIANCE

The RMF3 form will not be processed if a Facility Operator fails to satisfy the reporting requirements for registering a *Well/Well Group* or *Injection Scheme*.

NOTE: EFFECTIVE JANUARY 1999 ONWARDS, THE PENALTY OF $1000 PER MONTH OR PART OF A MONTH, FOR FAILURE TO FILE THE RMF3 BY ITS DUE DATE IS REMOVED.

AMENDING A SINGLE WELL/WELL GROUP/INJECTION SCHEME SETUP/CHANGE

- For amendments to Single Well or to Non-Consolidated Well Group information, Parts 1 and 2 must always be completed in full.
- For amendments to Injection Scheme information, Part 1 must always be completed in full and Parts 3 and 4 must be completed as required.

**For definition, please see Appendix N - Glossary.*

RMF3 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT INFORMATION

THIS SECTION OF THE FORM MUST BE COMPLETED FOR ALL RMF3 SUBMISSIONS.

1.1 **OPERATOR ID** - The four-character EUB operator code that identifies the Facility Operator submitting the form.

1.2 **OPERATOR NAME** - The full name of the Facility Operator whose code appears in *field 1.1.*

1.3 **DATE PREPARED** - The numeric year, month and day on which the RMF3 form is prepared.

1.4 **CONTACT PERSON** - The name of the person whom the Department can contact concerning the information on the form.

1.5 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: WORKING INTEREST OWNERSHIP *(W.I.O.)**

This section of the form:

- must be completed for all single wells and injection schemes that have a Crown interest of greater than 0% but less than 100%.
- must be completed for joint operating agreements (JOAs), non-unit gas, non-unit spacing, non-unit oil (solution gas) and projects that have less than 100% Crown. The identifier of these streams must begin with "A" and the stream type should be "WG". Where "WG" is used on this form, it signifies a Non-Consolidated Well Group.
- is not required to be completed if all the working interest owners' Crown interest is the same as that of the well's or injection scheme's Crown interest.

2.1 **STREAM ID** - The identifier assigned by the EUB or the Department to the *Well Event* or *Well Group (WG)* (explained above) that is the subject of the report. The first four letters comprising the Provincial Code and Stream ID type must be indicated before the identification code.

2.2 **UPDATE CODE** - Enter a "1" in this field if the form is submitted to set up a new *Well or Well Group* or a "2" if the form is submitted to change or terminate an existing *Well or Well Group.*

2.3 **PRODUCT NAME** – The product name if the RMF3 is for a specific product type. Valid products are: Gas, Ethane, Propane, Butane, Pentanes-plus and Sulphur.

NOTE: IF THE RMF3 IS FOR ALL GAS AND GAS PRODUCTS, THIS FIELD CAN BE LEFT BLANK.

2.4 **EFFECTIVE DATE** - The numeric year and month in which the setup is to become effective. The effective date will be the first day of that production month.

2.5 **TERMINATION DATE** - The numeric year and month in which the *Well* or *Well Group setup is to be terminated.* The effective date of the termination will be the first day of that production month. To terminate a well or well group from the original effective date, the termination date must be the same as the original effective date.

2.6 **TOTAL CROWN %** - The total Crown interest in the *Well* or *Well Group.*

For definition, please see Appendix N – Glossary.

2.7 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number that identifies the royalty client who is a *working interest owner* in the *Well, Well Group,* or *Injection Scheme.*

2.8 **CLIENT NAME** - The full name of the royalty client whose code appears in *field 2.7.*

2.9 **W.I.O. %** - The working interest ownership percentage of the royalty client identified in *fields 2.7 and 2.8* in the *Well, Well Group,* or *Injection Scheme*.

NOTE: THE TOTAL OF THE WORKING INTEREST OWNERSHIPS FOR ALL ROYALTY CLIENTS IDENTIFIED ON PART 2 OF THE RMF3 FORM MUST EQUAL 100%. ANY AMENDMENT TO WORKING INTEREST OWNERSHIP PERCENTAGE MUST RESULT IN COMPLETING PART 2 IN FULL.

2.10 **CROWN %** - The Crown interest percentage in the portion of the *Well, Well Group,* or *Injection Scheme* for the royalty client identified in *fields 2.7 and 2.8*.

PART 3: INJECTION SCHEME INFORMATION

THIS SECTION OF THE FORM MUST BE COMPLETED FOR ALL INJECTION SCHEMES.

3.1 **SCHEME ID** - The identifier assigned by the Department to the Injection Scheme that is the subject of the report:

- if the RMF3 is submitted for an ***initial setup,*** leave this field blank; the *proposed Injection Scheme* will not have a Department-assigned ID; *or*
- if the RMF3 is submitted to ***change or terminate*** an *existing Injection Scheme,* enter the INJECTION SCHEME ID assigned by the Department.

3.2 **NAME** - The name of the Injection Scheme.

3.3 **INJECTION FACILITY ID**– the identifier assigned by the EUB to the Injection Facility that is tied to the injection scheme reported under 3.1 and 3.2.

3.4 **NAME** – The name of the Injection Facility.

3.5 **UPDATE CODE** - Enter a "1" in this field if the form is submitted to set up a *new Injection Scheme*, or a "2" if the form is submitted to change or terminate an *existing Injection Scheme.*

3.6 **EFFECTIVE DATE** - The numeric year and month in which the setup or change is to become effective. The effective date will be the first day of that production month.

3.7 **TERMINATION DATE** - The numeric year and month in which the *Injection Scheme is to be terminated.* The effective date of the termination will be the first day of that production month. To terminate the Injection Scheme from the original effective date, the termination date must be the same as the original effective date.

3.8 **INJECTION SCHEME TYPE** - Check one box to indicate the type of Injection Scheme: *either*

ENHANCED OIL RECOVERY SCHEME,
CYCLING SHCEME,
PRESSURE MAINTENANCE SCHEME*
COMMERCIAL STORAGE SCHEME,
STORAGE SCHEME,
OTHER (EXCLUDING WATER FLOOD).

If OTHER is checked, give a description of the scheme type in the space provided.

For definition, please see Appendix N – Glossary.

PART 4. UNIQUE WELL IDs WITHIN AN INJECTION SCHEME

THIS SECTION OF THE FORM MUST BE COMPLETED FOR ALL INJECTION SCHEMES. PLEASE NOTE THE FOLLOWING:

- FOR ENHANCED OIL RECOVERY AND COMMERCIAL STORAGE SCHEMES, BOTH THE INJECTION AND PRODUCING WELLS MUST BE REGISTERED; *AND*
- FOR ALL OTHER TYPES OF *INJECTION SCHEMES* OTHER THAN WATER FLOOD (I.E., CYCLING, PRESSURE MAINTENANCE, ETC.) THE INJECTION WELLS MUST BE REGISTERED.

4.1 **FIELD/POOL CODE** - The EUB codes for the *field* and *pool* into which gas or gas products are injected by the Injection Scheme that is the subject of the RMF3.

4.2 **UPDATE CODE** - Enter a "1" in this field if the action is to *add a new Well Event* to the *Injection Scheme* or a "2" if the action is to *change or terminate an existing Well Event* in the *Injection Scheme.*

4.3 **UNIQUE WELL ID** - The unique well identifier assigned by the EUB to the *Well Event* that is to be added, changed or terminated.

4.4 **EFFECTIVE DATE** - The numeric year and month in which the *Well Event* is to be added to the *Injection Scheme*. The effective date will be the first day of that production month.

4.5 **TERMINATION DATE** - The numeric year and month in which the *Well Event* is to be terminated from the *Injection Scheme*. The effective date will be the first day of that production month.

4.6 **PAGE___OF___** - The page number of each individual page followed by the total number of pages submitted for each *Injection Scheme.*

4.7 **UNIT/WG CODE** - The five-digit code assigned by the Department for the wells that have been unitized or for the wells that comprise of the non-consolidated *Well Group*.

NOTE: AN RMF3 CONTINUATION PAGE IS PROVIDED TO ACCOMMODATE LARGER INJECTION SCHEMES. THE CONTINUATION PAGE INCLUDES ONLY THAT INFORMATION NOTED FOR SECTION 4, AND THE PROCEDURES FOR COMPLETING IT ARE THE SAME. PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", IN THE BOTTOM SPACE OF PART 4, IF APPLICABLE.

21.4 Owner Activity Statement (OAS)

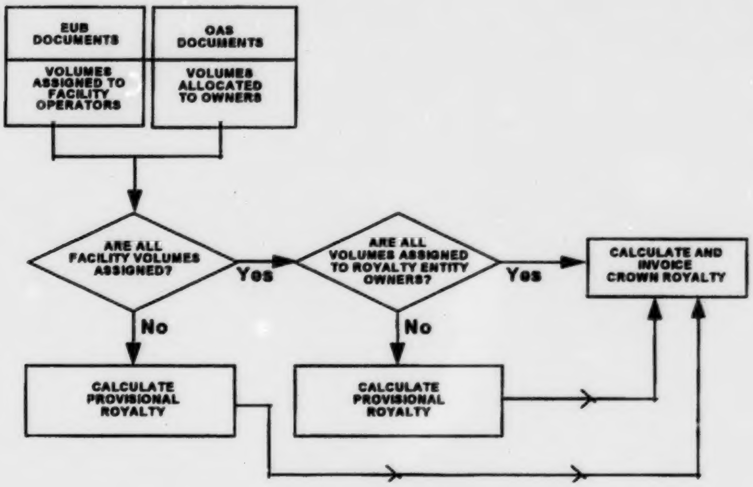
PREPARING AN OWNER ACTIVITY STATEMENT

The Owner Activity Statement (OAS) is the first in a series of petroleum and natural gas industry reports to be introduced by the *Partner Regulatory Information Data Exchange (PRIDE)* initiative. *PRIDE* is a collaborative industry and multi-government initiative focused on re-engineering the requirements of industry to industry and industry to government reporting. The Alberta Department of Resource Development is a participating member of PRIDE.

The Department has agreed that the reporting requirements established by PRIDE for the OAS will be adopted for reporting purposes, subject to the business rules required to provide acceptable assurance that the Crown royalty share is correctly determined and collected. The business rules relating to determining the Crown royalty share are outlined in *Sections 4 and 5*. The business rules that deal directly with the Department's requirements for OAS reporting are described in *Sections 4.4, 4.7 and 5.3.3.*

RECONCILING AN OWNER ACTIVITY STATEMENT

The Department will reconcile OAS reports to EUB volume information and to other OAS reports with which they are associated. The following is a summary level schematic of the reconciliation process.


EUB DOCUMENTS
VOLUMES ASSIGNED TO FACILITY OPERATORS
OAS DOCUMENTS
VOLUMES ALLOCATED TO OWNERS
ARE ALL FACILITY VOLUMES ASSIGNED?
Yes
No
ARE ALL VOLUMES ASSIGNED TO ROYALTY ENTITY OWNERS?
Yes
No
CALCULATE AND INVOICE CROWN ROYALTY
CALCULATE PROVISIONAL ROYALTY
CALCULATE PROVISIONAL ROYALTY

The business rules for volume allocations and OAS responsibility are described in *Sections 4.3, 4.4 and 5.3.*

The volume reconciliation process is described in detail in *Appendix A*.

21.5 OAS Reporting

21.5.1 Timing

Completed OAS documents must be received by the Department on or before the 15th day of the second month following the production month.

Consequence of Non-Compliance

A facility operator who fails to submit the completed OAS by the due date will be charged a penalty of $1,000 for each month or part of a month during which the failure continues. The penalty is calculated from the due date until the report is received by the Department. The penalty will be charged to the operator responsible for submitting the OAS, and will be reported on his Invoice. The operator will also be subject to provisional assessment.

If an **upstream facility***** operator (cascading facility operator) does not submit an OAS report by the due date, that operator will not be charged a penalty, but will be provisionally assessed on the Crown share of the volumes.

21.5.2 Reporting Level

All OAS volumes must be reported at the highest level (i.e., well/well group (both consolidated/non-consolidated), unit or injection scheme (*refer to Section 4.6.1*)). Holiday wells must be reported as single wells.

21.5.3 Production from Injection Schemes

All producing wells in an EOR scheme (identified on the RMF3 form) must be reported on the OAS with the EOR (injection) scheme number in the Stream ID column, and not a *Well/Well Group/Unit* number. This is necessary in order to recapture the operating costs on indigenous volumes. For non-EOR injection-related **production*** volumes, the Stream ID will depend on whether or not the producing wells were set up on the RMF3 under their respective injection scheme number. For producing wells set up on the RMF3, the Stream ID on the OAS must indicate the injection scheme number. For those producing wells not set up on RMF3, the Stream ID must be the *well, well group or unit.*

21.5.4 OAS Reporting Requirements

TO ASSESS GAS ROYALTY, THE DEPARTMENT RELIES ON DATA OBTAINED FROM INDUSTRY'S OAS REPORTING SYSTEM. BASED ON PRIDE RELEASE 3 DATED JUNE 6, 1994, THE DEPARTMENT WILL RELY ON THE FOLLOWING:

a) At facilities where previously unsold, unprocessed gas is throughput without **processing***:
  - all sales and exchange sales must be reported;
  - all transfers of unsold gas to Mainline Straddle Plants, transportation facilities, Oil Sands Projects and similar facilities outside of **royalty network*** must be reported; *and*
  - all transfers of unsold gas to facilities where products can be injected must be reported.

b) At facilities where previously **unsold gas stream*** is processed:
  - all lease fuel sales or deemed lease fuel sales (i.e., ineligible lease fuel) must be reported as processed or sale volumes on gas plant's OAS, or gas gathering system's OAS, respectively;

**For definition, please see Appendix N – Glossary.*

- all processing must be reported net of fuel. All NGL product mixtures extracted during processing must be reported at a component level;
- all transfers of unsold gas to facilities *other than* Field Straddle Plants, Mainline Straddle Plants and transportation facilities must be reported;
- all transfers of unsold gas to transportation facilities which subsequently returns to the network for use as eligible fuel (i.e., returned fuel) must be reported; *and*
- all transfers of unsold gas to facilities where gas and gas products can be injected must be reported.

c) At facilities where previously unsold processed gas is throughput without further processing:

- all lease fuel sales or deemed lease fuel sales (i.e., ineligible lease fuel) must be reported as processed or sale volumes on gas plant's OAS, or gas gathering system's OAS, respectively;
- all eligible fuel quantities must be reported;
- all flare and vented quantities must be reported;
- all measurement differences between stream receipt and delivery quantities must be reported;
- all transfers of unsold gas must be reported;
- all transfers of unsold gas to transportation facilities which subsequently returns to the network for use as eligible fuel (i.e., returned fuel) must be reported; *and*
- all transfers of unsold gas to facilities where gas and gas products can be injected must be reported.

At the end of OAS cascading, all of the above must be reported at a *Well/Well Group/Unit/Injection Scheme* level.

d) At facilities where gas and gas products can be injected:

- all quantities of gas and gas products received for the purpose of injection must be reported, indicating the purpose and target injection scheme ID;
- all quantities of NGL product mixtures received for the purpose of injection must be reported at a component level;
- all transfers of unsold product from these facilities must be reported; *and*
- all sales of product from these facilities must be reported.

e) Also:

- all quantities of gas and gas products received from Field Straddle Plants and transportation facilities must be reported;
- all sales of gas within royalty network (batteries, gathering systems, gas plants, field straddle plants if gas is unprocessed) must be reported, indicating the destination of the product movement. Sales of unprocessed gas indicating a "processing" facility as the destination will be valued at 80% of Gas Reference Price. Should other situations warrant the 80% valuation, clients may identify these to the Department for review. If justified, an adjustment to the valuation will be made;
- all purchases of gas within royalty network (batteries, gathering systems, gas plants, field straddle plants if gas is unprocessed) must be reported, indicating the destination of the product movement; *and*
- all exchanges of gas within royalty network (batteries, gathering systems, gas plants, field straddle plants if gas is unprocessed) must be reported indicating the destination of the product movement.

f) The OAS reporting for gas dispositions (sales and transfers) at a processing plant that are not processed at the plant (i.e., flow-through volumes) must be differentiated from the gas dispositions which are processed at the plant. Flow-through volumes must carry a different stream ID than the volumes being processed at the plant, and must not be cascaded to the same upstream facility.

g) Gas dispositions at a gathering system should be reported on the OAS activity as a "Transfer" or "Sale" with the appropriate destination of the product movement. Liquid products produced at a gathering system (e.g., pentanes) are to be reported on the OAS activity as "Process".

h) Operators who submit OAS documents for more than one owner must begin the page numbering at page one for each new owner. Page numbering is specific to operator, facility, owner, and production month.

I) Holiday wells must be reported as single wells on the OAS to receive holiday benefits.

21.5.5 OAS Amendments

- OAS amendments for owners must be full form replacements. The filing date on the new OAS must be later than the filing date on the previous OAS; otherwise, the OAS will be rejected.
- If there is a retroactive change to a well's vintage or Crown interest and the well is no longer eligible to be included in the consolidated well group, then the OAS must be refiled to allocate volumes to the well and the consolidated well group. Failure to amend the OAS document will result in the rejection of an incorrect OAS detail line record(s) and provisional assessment. Also, the RMF1 form must be refiled to reflect the change in the consolidated well group
- Where an OAS was filed incorrectly (e.g., to a wrong owner), it can be deleted by refiling. The amending OAS should indicate identical header information but with a later "Date Prepared" date and must include one line of valid detail data with zero volumes.

21.6 Royalty Triggers and OAS Reporting Rules for Royalty Assessment

The Department has agreed that the reporting requirements established by PRIDE for the OAS will be adopted for royalty assessment. Using the OAS data provided by facility operators, the Department assesses royalty at facilities for the owner of each product stream. Assessment is primarily based on what happens at a facility. Different royalty assessment methods are used depending on whether the previously unsold product stream is **processed*** or **unprocessed***.

Please refer to *Appendix B* for a detailed illustration of Royalty Triggers and OAS Reporting Rules for Royalty Assessment.

For definition, please see Appendix N - Glossary

21.7 OAS Reconciliation

An OAS reconciliation is done to ensure that quantities which should be accounted for according to EUB "S" (to be replaced in the future by Facility Activity Statement (FAS)) data are reported on the OAS. In addition, OAS quantities subject to reconciliation that are cascaded to upstream facilities are accounted for by the operators of the upstream facility. Included in the OAS reconciliations are the sales to purchases reconciliation between the facility that reported the sales and the facility that reported the purchases. However:

- No "S" to OAS reconciliation will be performed for mainline straddle plants and fractionation plants; *and*
- No "S" to OAS reconciliation will be performed if the facility is a battery.

NOTE: OAS VOLUME RECONCILIATION TOLERANCE HAS BEEN ESTABLISHED TO AVOID ASSESSING INSIGNIFICANT RECONCILIATION DIFFERENCES.

Please refer to *Appendix A* for detailed examples of reconciliations.

21.8 Validation Rules - Owner Activity Statement (OAS)

All OAS transmissions will be subject to validation rules or edits established by the Department. These are also defined as the "Data Element Validation Rules" in the PRIDE manual. The objective of the edits is to ensure that OAS reporting does not contain any element, which will affect the correctness and accuracy of the calculation of Crown royalty.

The edits are divided into three categories. They are:

- edits which will result in rejecting the entire OAS;
- edits which will result in inactivation of the entire OAS; *and*
- edits which will result in rejecting the OAS line record.

A complete detail of all the validation rules are described in *Appendix C.*

22. Valuing Raw Gas, Residue Gas and Ethane (Valuation Methodology)

22.1 Electing a Valuation Method

VA1 FORM - ELECTION FOR GAS VALUATION

PURPOSE

Royalty clients must use the VA1 form to elect their choice of valuation method, both for an initial election and for a subsequent election to change from CAP to Gas Reference Price valuation.

A description of the eligibility requirements for the election is provided in *Section 6.1.1. and 6.5.2.*

TIMING

A VA1 form to make an initial election must be received by the Team Leader, Client Services Help Desk:

- on or before June 15, 1994, if the person was a registered royalty client prior to 1994; *or*
- on or before the 15th day of the second month following the production month in which the person becomes a royalty client, if that person was not a registered royalty client prior to 1994.

To change from CAP to Gas Reference Price valuation, the Team Leader, Client Services Help Desk must receive a VA1 form, filed by a royalty client who has a valid CAP election in force, on or before March 1 of the year in which the change in election is to take effect.

CONSEQUENCES OF NON-COMPLIANCE

If a VA1 election does not meet the eligibility requirements of the valuation method that has been chosen, the VA1 form will be returned to the applicant with a notice identifying the deficiencies in the application. The applicant has 30 days from the date on the notice to correct the identified deficiencies and submit a corrected VA1 election form to the Department.

A royalty client who does not comply with the requirements for an initial election, he as well as all his associates will be deemed by the Minister to have chosen Gas Reference Price and their Crown royalty share will be invoiced at that price.

VA1 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the royalty client for whom the election is being made.

1.2 **CLIENT NAME** - The full name of the royalty client for whom the election is being made.

1.3 **PRODUCTION YEAR** - The production year in which the election is to become effective.

1.4 **DATE PREPARED** - The numeric year, month and day on which the VA1 form is prepared.

1.5 **CONTACT PERSON** - The name of the person whom the Department can contact concerning information on the form.

1.6 1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

1.7 **INITIAL or SUBSEQUENT** - Check one box, either INITIAL or SUBSEQUENT.

- INITIAL indicates that the election is for the implementation year (1994) or for the first year in which the person became a registered royalty client.
- SUBSEQUENT indicates that the royalty client has a valid CAP election and wishes to change to Gas Reference Price.

PART 2: VALUATION METHOD

2.1 **CHECK ONE** - Check one box, either REFERENCE PRICE or CORPORATE AVERAGE PRICE.

- REFERENCE PRICE indicates that the royalty client making the election wishes to have his Crown royalty share of raw gas, residue gas and ethane valued at the Gas Reference Price beginning in the production year indicated in *field 1.3*.
- CORPORATE AVERAGE PRICE indicates that the royalty client making the election wishes to have his Crown royalty share of raw gas, residue gas and ethane valued at the Gas Corporate Average Price beginning in the production year indicated in *field 1.3*.

PART 3: ASSOCIATES

3.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is an associate of the royalty client for whom the election is being made. *(If the associate is not a royalty client and does not have an EUB operator code, this requirement does not apply.)*

3.2 **CLIENT NAME** - The full name of the person who is an associate of the royalty client for whom the election is being made.

For the purpose of raw gas, residue gas and ethane valuation, persons are associated if one person owns or has a beneficial interest equal to or greater than 75% of the other person, whether directly or in combination with other associates.

PART 4: OFFICIAL DECLARATION

4.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer of the royalty client for whom the election is being made.

4.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 4.1*.

4.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 4.1*.

4.4 **DATE** - The date on which the authorized signing officer signed the VA1 election form.

22.2 Preparing a Gas Corporate Average Price Calculation

VA2 FORM - CORPORATE AVERAGE PRICE CALCULATION - GAS

PURPOSE

Royalty clients must use the VA2 form to submit their calculation of the Gas Corporate Average Price at which their Crown royalty share of raw gas, residue gas and ethane will be valued. If a royalty client needs to amend his CAP calculation for a previous year, the VA2 form is used to calculate and report the amendment as well.

A description of the business rules associated with calculating the annual CAP is provided in *Section 6.5. and Section 14.3.*

TIMING

The Client Services Help Desk must receive a completed VA2 form, for each royalty client who uses CAP, on or before April 15th of the year following the production year to which the CAP applies.

CONSEQUENCES OF NON-COMPLIANCE

Where a royalty client fails to satisfy the reporting and disclosure requirements for determining its CAP by August 15 following the production year to which the failure relates, the CAP election made by the royalty client and associates ceases to be valid effective the first day of the year to which the failure relates. As a result, the Crown royalty share of raw gas, residue gas and ethane will be valued at Reference Price effective the first day of the year to which the failure applies.

Effective January 1999 the penalty of $1000 per month or part of a month, for failing to file a VA2 form by its due date is replaced with a one time penalty charge of $1000 and the royalty client will be defaulted to Reference Price.

AMENDING A GAS CORPORATE AVERAGE PRICE

Where a royalty client receives adjustments to either the sale proceeds or costs relating to transactions that are included in the CAP calculation of a previous year, and a recalculation of the CAP for that previous year is required, an amended CAP calculation must be submitted using the VA2 form. The business rules associated with determining whether or not a recalculation is required are described in *Section 6.5. and Section 14.3.*

An amended VA2 form must be completed in full just as with an initial VA2 form.

VA2 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client for which the information is submitted.

1.3 **PRODUCTION YEAR** - The production year to which the CAP calculation applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the VA2 form is prepared.

1.5 **CONTACT PERSON** - The name of the person whom the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

1.7 **NO SALES/DISPOSITIONS** - If there are no sales or dispositions during the year, check this box and leave Parts 2, 3, 4, and 5 blank.

PART 2: ARM'S-LENGTH SALES

2.1 **TOTAL ANNUAL GJS** - Total arm's-length sales *(in gigajoules)* of the royalty client during the production year stated in *field 1.3*, broken down by type of purchaser:

- AGGREGATOR - a marketing company that contracts with and purchases large quantities of gas from many producers and resells it to a number of markets. Typically, the producers contract to sell their gas through a supply pool managed by the aggregator, and they are entitled to a vote in matters relating to the acceptability of contracts for sales from the supply pool.
- **MARKETER** - a marketing company that contracts with and purchases gas from one or more producers and resells the gas to one or more buyers *or* that acquires the gas from one or more producers, sells the gas and pays the producer a value based on a percentage of the selling price *(as **broker*****)*. Typically, producers who sell to marketers do not have a vote in the contracts through which the gas is resold.
- PRODUCER - a company that is involved in the production of petroleum and natural gas and which purchases gas for use in its own production-related operations.
- END-USER - a company that purchases gas for the purpose of **consumption***, either as fuel or as a raw material in its business operations, and which is not an aggregator, a marketer or a producer.

2.2 **GROSS ANNUAL REVENUE** - Total revenue *(in Canadian dollars)* from the sales reported in *column 2.1*, by type of purchaser. Storage costs deducted in the netback price paid by an aggregator must be added back to the revenue from the sale.

2.3 **TRANSPORTATION · INTRA-ALBERTA** - Total cost incurred by the royalty client to transport the gas reported in *column 2.1* within Alberta, including demand charges.

2.4 **TRANSPORTATION · EX-ALBERTA** - Total cost incurred by the royalty client to transport the gas reported in *column 2.1* outside Alberta, including demand charges, net of any revenue received from brokered pipeline capacity.

2.5 NET ANNUAL REVENUE - **The sum (Gross Annual Revenue *...minus...*intra-Alberta Transportation** *...minus...* ex-Alberta Transportation) by type of purchaser for all sales reported in *column 2.1*.

for definition, please refer to Appendix N - Glossary

PART 3: SALES TO ASSOCIATES (WITH A CAP)

3.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is an associate of the royalty client.

3.2 **CLIENT NAME** - The full name of the person who is an associate of the royalty client.

3.3 **TOTAL GJS** - Total sales *(in gigajoules)* to each associate who is identified in *columns 3.1 and 3.2* during the production year, which is to be valued at that associate's CAP.

3.4 **CAP** - The Gas Corporate Average Price of each associate identified in *columns 3.1 and 3.2*. If an associate is not a royalty client, attach a schedule *(using the non-royalty client's VA2 form)* substantiating the CAP calculation. If the associate is a royalty client, the Department will verify that associate's CAP based on his VA2 submission. The business rules for calculating the CAP of an associate are described in *Section 6.5*.

3.5 **TOTAL REVENUE** - The product of (Total GJs *...multiplied by...* CAP) for each associate.

PART 4: OTHER DISPOSITIONS

4.1 **TYPE 1** - Total gas sales *(in gigajoules)* during the production year, by month, to all associates who do not have a CAP. The business rules for determining whether or not an associate must calculate a CAP are described in *Section 6.5*. A royalty client who is uncertain about valuing sales to associates should seek an advance ruling from the Department.

4.2 **TYPE 2** - Total gas consumed *(in gigajoules)* during the production year, by month, by the royalty client in his own operations. Consumed means gas used as fuel in an industrial process.

4.3 **TYPE 3** - Total gas otherwise disposed *(in gigajoules)* during the production year, by month, without an arm's-length sales transaction.

4.4 **TOTAL GJS** - The sum of Type 1 *...plus...* Type 2 *...plus...* Type 3 "Other Dispositions" *[in gigajoules]* for each month during the production year.

4.5 **REFERENCE PRICE** - The published Gas Reference Price for each month during the production year.

4.6 **TOTAL REVENUE** - The sum of the product (Total GJs *...multiplied by...* Reference Price) for each month of the production year.

PART 5: CAP CALCULATION

5.1 **$ PER GJ** - The total revenue of (sum of all revenues shown in *columns 2.5, 3.5 and 4.6*) *...divided by...* the total quantity (sum of all gigajoules shown in *columns 2.1, 3.3 and 4.4*), calculated to the nearest one-tenth of a cent.

PART 6: CERTIFICATION

6.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the royalty client who is responsible for the information submitted.

6.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 6.1*.

6.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 6.1*.

6.4 **DATE** - The date on which the authorized signing officer signed the VA2 form.

22.3 Preparing an Application to Grandfather a Co-Generation or Other Long-Term Contract

GR1 FORM - APPLICATION TO GRANDFATHER CO-GENERATION OR OTHER LONG-TERM CONTRACTS

NOTE: ROYALTY CLIENTS ELECTING REFERENCE PRICE VALUATION AFTER JUNE 15, 1994, ARE NOT ELIGIBLE TO GRANDFATHER CONTRACTS.

PURPOSE

Royalty clients must use the GR1 form to submit their application to grandfather the pricing provisions of co-generation and similar long-term contracts.

A description of the eligibility requirements for the election is provided in *Section 6.4.1.*

TIMING

For each co-generation or similar long-term contract that a royalty client wishes to have grandfathered, the Client Services Help Desk must have received a GR1 form filed to make an election on or before June 15, 1994.

CONSEQUENCES OF NON-COMPLIANCE

A GR1 application that does not satisfy the eligibility requirements for grandfathering the subject contract will be rejected and returned to the applicant with a notice identifying the deficiencies in the application.

A GR1 application that is received after the June 15, 1994 due date will be rejected and returned to the applicant without further consideration.

GR1 FORM - COMPLETION INSTRUCTIONS

PART 1: ROYALTY CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department, which identifies the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client for whom the application is being made.

1.3 **DATE PREPARED** - The numeric year, month and day on which the GR1 form is prepared.

1.4 **CONTACT PERSON** - The name of the person whom the Department can contact concerning information on the form.

1.5 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: DEDICATED RESERVES

THIS SECTION MUST BE COMPLETED IF THE SUBJECT CONTRACT INCLUDES A RESERVE DEDICATION CLAUSE AND THE ROYALTY CLIENT WISHES TO HAVE THE CROWN ROYALTY SHARE APPLIED AGAINST THE PRODUCTION FROM THOSE RESERVES.

2.1 **STREAM ID** - The stream ID number assigned by the EUB/Department to the well or group of wells producing gas from the reserves identified as being dedicated to the subject contract.

PART 3: CONTRACT INFORMATION

3.1 **CONTRACT NO./ID** - The unique name or number assigned for identification purposes to the contract that is the subject of the application.

3.2 **PARTIES TO CONTRACT** - The full name of each person who is a signatory to the subject contract.

3.3 **CONTRACT PRICE** - The unit value *(in dollars per GJ)* of the consideration given for gas supplied under the subject contract.

3.4 **BASIS FOR PRICE INCREMENTS** - The index, factor or other indicator against which the consideration given for gas supplied under the subject contract is incremented.

3.5 **FREQUENCY OF PRICE INCREMENTS** - The number of times that the consideration given for gas supplied under the subject contract is incremented *(e.g., twice per year)*.

3.6 **TERM OF CONTRACT** - The duration of the subject contract, in years and/or months, from the effective date to the termination date. Contract renewals or options to renew may not be included in the term of the contract.

3.7 **EFFECTIVE DATE** - The year, month and day that the subject contract became effective.

3.8 **COPY OF CONTRACT ATTACHED** - Check this box to indicate that the required copy of the subject contract is attached to the GR1 application.

3.9 **COLLATERAL AGREEMENTS** - The unique name or number assigned by the royalty client, for identification purposes, to any auxiliary or subsidiary agreements that are attached with the contract that is the subject of the application.

PART 4: CERTIFICATION

4.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the royalty client for whom the application is being made.

4.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 4.1*.

4.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 4.1*.

4.4 **DATE** - The date on which the authorized signing officer signed the GR1 application.

22.4 Preparing an Annual Statement of Grandfathered Contract Sales

GR2 FORM - ANNUAL STATEMENT OF GRANDFATHERED CONTRACT SALES

PURPOSE

Royalty clients must use the GR2 form to submit delivery and price information relating to contracts that have been authorized for grandfathered valuation of the Crown royalty share. If a royalty client needs to amend his GR2 form submission for a previous year, the GR2 form is used to submit that information as well.

A description of the business rules associated with grandfathered contracts is provided in *Section 6.4.1.*

TIMING

For each contract that is the subject of an authorized grandfathering election, a completed GR2 form must be received by the Client Services Help Desk by March 31 of the year following the production year to which the information applies.

CONSEQUENCES OF NON-COMPLIANCE

Where a royalty client's Annual Statement of Grandfathered Contract Sales is in default for four consecutive months after the due date of March 31, the royalty client loses the election to grandfather co-generation or long term contracts. The volumes subject to these contracts will be valued at the applicable monthly Reference Price.

Effective January 1999 the penalty of $1000 per month or part of a month, for failing to file a GR2 Form by its due date is replaced with a penalty charge of $1000 for four months and the royalty client will be defaulted to Reference Price.

AMENDING A STATEMENT OF GRANDFATHERED CONTRACT SALES

If a royalty client receives an adjustment to transactions that were included in the GR2 submission from a previous year, an amended GR2 form must be submitted to the Department.

An amended GR2 form must be completed in full just as with an initial GR2 form.

GR2 FORM - COMPLETION INSTRUCTIONS

PART 1: ROYALTY CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client for whom the information is being submitted.

1.3 **PRODUCTION YEAR** - The production year to which the information applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the GR2 form is prepared.

1.5 **CONTRACT NO./ID** - The unique name or number assigned for identification purposes to the contract for which the information is submitted.

1.6 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.7 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: DETAILS OF CONTRACT SALES BY MONTH

2.1 **GJS DELIVERED** - The quantity of gas *(in gigajoules)* delivered under the subject contract, by month, during the production year.

2.2 **CONTRACT SELLING PRICE** - The consideration payable for gas *(in $ per GJ)* delivered under the contract, by month, as specified in the subject contract.

2.3 **NETBACK SELLING PRICE** - The value per unit *(in $ per GJ)* received, net of incurred allowable transportation costs from the Alberta plant gate to the **point of delivery*** for the monthly deliveries identified in *column 2.1*.

PART 3: CERTIFICATION

3.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the royalty client who is responsible for the information submitted.

3.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 3.1*.

3.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.1*.

3.4 **DATE** - The date on which the authorized signing officer signed the GR2 submission.

For definition, please see Appendix N - Glossary

23. Valuing Gas Products

23.1 Preparing an NGL Valuation and Transportation Submission

NGL1 FORM - NGL VALUATION AND TRANSPORTATION

PURPOSE

The designated purchasers of NGL in Alberta use the NGL1 form to report the volume and acquisition cost of propane and butane purchased during the month at an Edmonton-based price and the transportation cost during the month for specification propane/butane, specification pentanes-plus and NGL mix.

The information provided on the NGL1 forms is used to calculate the Propane Reference Price, the Butane Reference Price and the regional Transportation Allowances. One designated purchaser's NGL1 submissions are subject to the list of exceptions identified under "Exceptions" at the end of Part 3 for both 1994 and post-1994 NGL1 reporting.

If a designated purchaser needs to amend his NGL1 submission for a previous month, the NGL1 form is used to submit that information as well.

The business rules for propane, butane and pentanes reference prices, and for transportation allowances, are described in *Section 6.5. and Sections 15.1 to 15.3.*

TIMING

The Department must receive a completed NGL 1 form on or before the 10th day of the second month following the production month to which the information applies.

CONSEQUENCES OF NON-COMPLIANCE

A designated purchaser who fails to satisfy the reporting requirements for propane and butane volumes/acquisition cost and transportation cost is subject to penalties.

The penalty for failing to file a completed NGL1 form with the Department by the due date is $1,000 for each month or part of a month during which the failure continues. The penalty is calculated from the due date for the form until the date the form is received by the Department.

AMENDING AN NGL1 SUBMISSION FOR A PREVIOUS PERIOD

Changes to a previous month, if required, may be one of two types. The reporting rules for each of the types are as follows:

- TYPE 1 - CHANGES RESULTING FROM REDETERMINATION OR REALLOCATION OF DATA BY A PIPELINE, A PRODUCER, A SHIPPER OR A CUSTOMER - changes must be included in the information provided for the month in which the change is received.
- TYPE 2 - CHANGES RESULTING FROM ERRORS AND OMISSIONS - errors and omissions that result in the designated purchaser's NGL1 information for a month differing from its corporate records must be reported to the Ministry on an amended NGL1 for that month. An amended NGL1 form must be completed in full just as with an initial NGL1 form.

NGL1 FORM - COMPLETION INSTRUCTIONS

PART 1: DESIGNATED PURCHASER DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the Designated Purchaser.

1.2 **CLIENT NAME** - The full name of the Designated Purchaser for which the information is being submitted.

1.3 **PURCHASE YEAR/MONTH** - The purchase year and month to which the information applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the NGL1 form is prepared.

1.5 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code, of the contact person.

1.7 **AMENDMENT** - Check this box only if the NGL1 form amends the information submitted on a previous NGL1 form.

PART 2: REFERENCE PRICE INFORMATION

2.1 & 2.2 a) Report all arm's-length purchases in Alberta of propane (C3) and butane (C4) where the contract purchase price references an Edmonton price. Include volumes destined for Edmonton and other markets. All reference price information must be reported in cubic metres and in Canadian dollars (before GST).

b) Include purchases at all points except mainline straddle plants and facilities other than gas processing plants in the Edmonton and Fort Saskatchewan area as defined below.

c) Propane volumes are the restated volumes after the ethane penalty has been applied (2% limit).

d) Include buy/sell and exchange where an invoice exists (valid market price).

e) Where a portion of a contract's volume is based purely on an Edmonton posting, report that portion only. Exclude any volumes priced on a blending of Edmonton and non-Edmonton based postings.

f) Report spec product purchases allocated from an NGL mix and actual spec product purchases based only on contracts that are in place.

2.3 **AVERAGE EDMONTON UNIT COST ($/M^3)** - The weighted average unit cost for the month for each of propane and butane, calculated as 2.1 ...*divided by*... 2.2.

PART 3: TRANSPORTATION INFORMATION

Spec Product (C3 and C4) and NGL Mix

a) C3 and C4 that are purchased as spec are to be reported in the "Spec Product" column. C5+ that is purchased as spec are to be reported in the "Spec Pentanes" column.

b) C3, C4 and C5+ that are purchased as a mix are to be reported under "NGL Mix" (no splitting out components in Part 3).

c) Report transportation differentials for those contracts reported under Part 2. This transportation differential is calculated as follows:

(Gross Acquisition Cost
...minus...
Actual Acquisition Cost
...minus...
Fractionation Cost (for NGL Mix only)
...minus...
Actual Storage Cost (1994 only) and Other Fees (if the fees are specifically identified))
...divided by...
Volumes Purchased

d) For NGL Mix only, use the published fractionation allowance as "fractionation cost" above.

e) For 1994 only, if storage costs are identified on the invoice, use these actual fees as "storage cost" above. The storage costs are not deductible for production year 1995 onwards.

f) If other fees are specifically identified on the invoice, use actual costs as a deduction above, otherwise use zero. "Other fees" includes deductions such as:

- distribution fees;
- marketing fees;
- handling fees;
- processing fees;
- de-ethanization fees (not applicable if fractionation allowance includes an allowance for de-ethanization cost);
- pipeline equalization charges; *and*
- any other fee or charge that is not directly related to transporting the product.

Spec Pentanes

a) Spec pentanes reporting should include both gas plant production and field condensate (largely pentanes-plus products obtained from natural gas or solution gas before it is delivered to a gathering system) at all purchase points in Alberta except mainline straddle plants and facilities other than gas processing plants in the Edmonton and Fort Saskatchewan area as defined below.

b) Report transportation differentials for all spec pentanes purchased at arm's-length at an Edmonton price. Include volumes destined for Edmonton and other markets.

The transportation differential is calculated as follows:

(Gross Acquisition Cost
...minus...
Actual Acquisition Cost
...minus...
Actual Storage Cost (for 1994 only) and Other Fees (if the fees are specifically identified))
...divided by...
Volumes Purchased

c) For "storage cost" and "other fees," refer to e) and f) above.

General Requirements

1) Report according to the region of purchase, as defined in *Appendix F*.

2) Report in cubic meters and Canadian dollars (before GST).

Exceptions

The following exceptions to the above rules apply only to one designated purchaser's NGL1 submissions. These are as follows:

For 1994 Production Year

- Specification product purchases are excluded from Part 2 reporting;
- Only volumes actually transported to Edmonton will be reported under Part 3; *and*
- Under Part 3, the NGL Mix transportation differentials must be reported for all arm's-length purchases irrespective of how acquisition costs were determined (i.e., contract pricing does not have to be Edmonton based).

For Post-1994 Production Years

- Under Part 3, in Region 4, the NGL Mix transportation differentials must be reported for all arm's-length purchases irrespective of how acquisition costs were determined (i.e., contract pricing does not have to be Edmonton based).

NOTE: **DEFINITION OF EDMONTON AND FORT SASKATCHEWAN AREA**

THE EDMONTON AND FORT SASKATCHEWAN AREA IS SPECIFICALLY DESCRIBED AS THE AREA FALLING WITHIN:

THE NORTHERN BOUNDARY OF TOWNSHIP 56,
THE SOUTHERN BOUNDARY OF TOWNSHIP 51,
THE EASTERN BOUNDARY OF RANGE 21, *AND*
THE WESTERN BOUNDARY OF RANGE 26,
ALL WEST OF THE 4TH MERIDIAN.

PART 4: CERTIFICATION

4.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the Designated Purchaser who is responsible for the information submitted.

4.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 4.1*.

4.3 **TITLE OF CORPORATE SIGNING OFFICER** – The position title of the authorized signing officer whose signature appears in *field 4.1*.

4.4 **DATE** - The date on which the authorized signing officer signed the NGL1 submission.

23.2 Preparing an NGL Storage Cost Submission

NGL2 FORM - STORAGE COSTS

NOTE: **THIS SECTION APPLIES ONLY FOR THE 1994 PRODUCTION YEAR. THE STORAGE ALLOWANCE FOR THE 1995 PRODUCTION YEAR AND ONWARDS IS SET AT $0 PER M^3. NGL2 IS NOT REQUIRED FOR 1995 AND ONWARDS.**

PURPOSE

Operators of designated NGL storage facilities in Alberta who charge for storage use the NGL2 form to report the volumes and associated costs for natural gas liquids stored, based on the year according to the designated storer's accounting records.

The information provided on the NGL2 form is used in calculating the natural gas liquids Storage Allowances.

If an operator of a designated storage facility needs to amend its NGL2 form submission for a previous prior year, the NGL2 form is used to submit that information as well.

The business rule for storage allowance is described in *Section 15.3.2.*

TIMING

The Department must receive a completed NGL2 form on or before the 15th day of the second month following the production year to which the information applies.

CONSEQUENCES OF NON-COMPLIANCE

The penalty for failing to file a completed NGL2 form with the Department by the due date is $1,000 for each month or part of a month during which the failure continues. The penalty is calculated from the due date for the report until the date the report is received by the Department, and will be charged to the operator of the designated storage facility.

AMENDING AN NGL2 SUBMISSION FOR A PREVIOUS PERIOD

If an operator of a designated storage facility receives an adjustment to transactions that are included in the NGL2 form for a previous year, or identifies errors or omissions in the submission of a previous year, an amended NGL2 form must be submitted to the Department. An amended NGL2 form must be completed in full just as with an initial NGL2 form.

NGL2 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the operator of the designated facility.

1.2 **CLIENT NAME** - The full name of the corporation that is the operator of the designated storage facility and for which the information is being submitted.

1.3 **EUB FACILITY NO.** - The unique facility code assigned by the EUB that identifies the designated storage facility.

1.4 **FACILITY NAME** - The name given to the designated storage facility.

1.5 **PRODUCTION YEAR** - The production year to which the information applies.

1.6 **DATE PREPARED** - The numeric year, month and day on which the NGL2 form is prepared.

1.7 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.8 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: STORAGE AREA INFORMATION

2.1 **TOTAL ANNUAL VOLUMES STORED (m^3)** - Total volumes of natural gas liquids stored in the designated facility during the year.

2.2 **TOTAL ANNUAL INVOICED AMOUNT ($)** - Total amount charged and invoiced for storage fees during the year for the volumes reported in *field 2.1.*

PART 3: CERTIFICATION

3.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the company who is the operator of the designated storage facility and who is responsible for the information submitted.

3.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 3.1.*

3.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.1.*

3.4 **DATE** - The date on which the authorized signing officer signed the NGL2 submission.

23.3 Preparing an Annual Sulphur Corporate Average Price (S-CAP) Calculation

VA3 FORM - ANNUAL CORPORATE AVERAGE PRICE CALCULATION - SULPHUR

PURPOSE

- All royalty clients who have filed monthly VA4 forms must file the VA3 form to submit their information for the annual S-CAP at which their Crown royalty share of gas plant sulphur will be valued.
- Those royalty clients who chose not to file monthly VA4 forms may file VA3 forms to report their annual S-CAP.
- Royalty clients who are not required and choose not to file a VA3 form will have their sulphur production valued at the annual Sulphur Default Price. There is no penalty for this.

The Department uses the information submitted on the VA3 form to calculate the S-CAP for the royalty client for each month of the year for which the VA3 form applies. Interest will be charged or paid on the Crown royalty difference resulting from the price adjustment from monthly to annual valuation.

A description of the business rules associated with calculating the annual S-CAP is provided in *Section 6.5.3 and Section 15.4.*

TIMING

A completed VA3 form must be received by the Client Services Help Desk on or before April 15 of the year following the production year to which the S-CAP applies.

CONSEQUENCES OF NON-COMPLIANCE

- Where a royalty client's Sulphur Corporate Average Price calculation (VA3) form is in default for three consecutive months after the due date of April 15, the Department will value the Crown royalty share of the royalty client using the annual Sulphur Default Price for the production year for which the VA3 form applies. Upon receipt of VA3, the Crown royalty share will be valued in the manner described in *Section 15.4.2.* Interest will be charged or paid on the Crown royalty difference between the value computed by using the Annual Sulphur Default Price versus the S-CAP.
- Those clients who are not required but choose to file VA3 forms must file them before the due date. Penalties will apply for late submission of the VA3 forms.

Effective January 1999 the penalty of $1000 per month or part of a month, for failing to file a VA3 form by its due date is replaced with a one time penalty charge of $1000.

AMENDING ANNUAL SULPHUR CORPORATE AVERAGE PRICE

An amended VA3 form must be completed in full just as with an initial VA3 form.

FORM VA3 - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client for whom the information is submitted.

1.3 **PRODUCTION YEAR** - The production year to which the S-CAP information applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the VA3 form is prepared.

1.5 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

1.7 **NO SALES** - If there are no sales during the year, check this box and leave Part 2 blank .

PART 2: ARM'S-LENGTH SALES

2.1 **POINT OF SALE** - The point of delivery for **volumes sold*** ***(for definition, please see Appendix N - Glossary)*** (NORTH AMERICA and OFF-SHORE).

2.2 **TONNES** - Total tonnes of Alberta gas plant-produced sulphur sold by the royalty client during the year, for each point of sale.

(The total tonnes of sulphur does not include other producer's share of sulphur if the royalty client also markets other producer's share of sulphur.)

2.3 **GROSS ANNUAL REVENUE** - Total gross annual revenue received for sulphur sales (tonnes) identified in *field 2.2.*

2.4 **TRANSPORTATION COSTS** - Total transportation costs incurred to transport sulphur (tonnes) identified in *field 2.2*, from the producing plant gate to the point of sale.

2.5 **STORAGE COSTS** - Total storage, loading and handling costs incurred as a direct consequence of the transportation of sulphur identified in *field 2.4.*

2.6 **NET ANNUAL REVENUE** - The Gross Annual Revenue …*minus*... Transportation Costs ...*minus*... Storage Costs.

PART 3: CERTIFICATION

3.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer of the royalty client who is responsible for the information submitted.

3.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 3.1.*

3.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.1.*

3.4 **DATE** - The date on which the authorized signing officer signed the VA3 form.

23.4 Preparing a Monthly Sulphur Corporate Average Price (S-CAP) Calculation

VA4 FORM - MONTHLY CORPORATE AVERAGE PRICE CALCULATION - SULPHUR

PURPOSE

All royalty clients having annual sulphur production of 30,000 tonnes or more (based on previous year's production) must file VA4 forms monthly to determine their S-CAP. The Department will notify the royalty clients who are in this category.

Those royalty clients whose annual sulphur production is less than 30,000 tonnes may choose to file VA4 forms monthly effective January's production month, and then, must continue to file VA4 forms for the entire year. New royalty clients who wish to file VA4 forms must file them effective the first production month in which they have sulphur allocation and then, must continue to file for the remainder of the year.

The Department values and invoices the Crown royalty share of sulphur production monthly using the royalty client's S-CAP.

A description of the business rules associated with calculating the annual S-CAP is provided in *Section 6.5.3* and *Section 15.4.*

TIMING

The Client Services Help Desk must receive a completed VA 4 form on or before the 15th day of the second month following the production month to which the S-CAP applies.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a VA4 form by its due date is replaced with a penalty of $100 per month or part of a month until the form is received.

The Crown royalty share of sulphur for the delinquent month will be valued and invoiced using that month's Sulphur Default Price. Upon receipt of the VA4 form, the Crown royalty share of sulphur will be valued in the manner described in *Section 6.5.3 and Section 15.4.1*. Interest will be charged or paid on the difference between the value computed by using the Monthly Sulphur Default Price versus the S-CAP.

AMENDING MONTHLY SULPHUR CORPORATE AVERAGE PRICE

An amended VA4 form must be completed in full just as with an initial VA4 form.

VA4 FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT DETAIL

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department that identifies the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client for whom the information is submitted.

1.3 **PRODUCTION YEAR/MONTH** - The production year and month to which the S-CAP information applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the VA4 form is prepared.

1.5 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

1.7 **NO SALES** - If there are no sales during the year, check this box and leave Part 2 blank.

PART 2: ARM'S-LENGTH SALES

NOTE: COMPLETION OF *FIELDS 2.1, 2.3, 2.4 AND 2.5* IS OPTIONAL.

2.1 **POINT OF SALE** - The point of delivery for volumes sold (NORTH AMERICA and OFF-SHORE).

2.2 **TONNES** - Total tonnes of Alberta gas plant-produced sulphur sold by the royalty client during the year, for each point of sale.

(The total tonnes of sulphur does not include other producer's share of sulphur if the royalty client also markets other producer's share of sulphur.)

2.3 **GROSS MONTHLY REVENUE** - Total gross monthly revenue received for sulphur sales (tonnes) identified in *field 2.2.*

2.4 **TRANSPORTATION COSTS** - Total transportation costs incurred to transport sulphur (tonnes) identified in *field 2.2*, from the producing plant gate to the point of sale.

2.5 **STORAGE COSTS** - Total storage, loading and handling costs incurred as a direct consequence of the transportation of sulphur identified in *field 2.4.*

2.6 **NET MONTHLY REVENUE** - The gross monthly revenue *...minus...* transportation costs *...minus...* storage costs.

PART 3: CERTIFICATION

3.1 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer of the royalty client who is responsible for the information submitted.

3.2 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 3.1.*

3.3 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.1.*

3.4 **DATE** - The date on which the authorized signing officer signed the VA4 form.

24. Alberta's Royalty Share of Allowable Costs

24.1 Preparing a Facility Cost Centre Setup/Change

AC1 FORM - ALLOWABLE COSTS FACILITY COST CENTRE SETUP/CHANGE

PURPOSE

Operators of Facility Cost Centres *(FCC Operators)* must use the AC1 form to register new Facility Cost Centres *(formerly GCA facilities),* or to change the information for an existing Facility Cost Centre. If a change in the Facility Cost Centre operator occurs, the Department must be notified by the operator currently registered with the Department. The AC1 form tells the Department which type of capital assets are included in the Facility Cost Centre and who owns and operates the Facility Cost Centre.

A completed AC1 form must be filed with the Department to establish a new Facility Cost Centre before an AC2 form *(annual Capital Costs)* or AC3 form *(annual Capital Re-allocations)* reporting can be accepted for processing by the Department.

A completed AC1 form must be filed with the Department to register changes to an existing Facility Cost Centre, before the AC2 and AC3 forms for the same year are submitted.

An AC1 form is not required if no changes occurred in the production year for which an AC1 form is filed.

A description of the business rules associated with establishing or changing a Facility Cost Centre is provided in *Section 16.3*

TIMING

The Client Services Help Desk must receive a completed AC1 form:

- on or before March 1 of the year following the production year in which a new Facility Cost Centre commences operation.
- on or before the last day of the month following the production month in which a Facility Cost Centre operator change occurs.

CONSEQUENCES OF NON-COMPLIANCE Penalty Removed

Effective January 1999 onwards, the penalty of $1000 per month or part of a month for failing to file a AC1 Form by its due date is removed.

FACILITIES ESTABLISHED PRIOR TO 1994

No reporting is required to establish a facility that is registered with the Department at December 31, 1993. However, because many pre-1994 *GCA facilities* included groupings of gathering, compressing and processing facilities, each Facility Operator should review his existing Facility Cost Centres to determine whether or not they should be separated into individual, specific Facility Cost Centres. It is desirable that Facility Cost Centres correlate as closely as possible with the Operating Cost Centres used to manage Operating Cost Allowances.

AMENDING A FACILITY COST CENTRE SETUP/CHANGE

For an amended AC1 form, Part 1 and *fields 2.1 to 2.4* of Part 2 must always be completed. Changes to *field 2.9* must always identify all previous Facility Cost Centres. All other fields should only be completed if the data in these fields needs to be amended.

AC1 FORM - COMPLETION INSTRUCTIONS

PART 1: FACILITY COST CENTRE OPERATOR DETAIL

1.1 **CHECK ONE** - Check SETUP if the form is submitted to register a new Facility Cost Centre *or* CHANGE if the form is submitted to change an existing Facility Cost Centre.

1.2 **DATE PREPARED** - The numeric year, month and day on which the AC1 form is prepared.

1.3 **REASON FOR CHANGE** - If the form is submitted to register a change, explain why the change is required.

1.4 **FACILITY COST CENTRE OPERATOR ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is the operator of the Facility Cost Centre.

1.5 **FACILITY COST CENTRE OPERATOR NAME** - The full name of the person who is the operator of the Facility Cost Centre.

1.6 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.7 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: FACILITY COST CENTRE

2.1 **FACILITY CODE**

- PROV. - the province in which the facility is located: Alberta (AB), British Columbia (BC), or Saskatchewan (SK).
- EUB FAC. TYPE - the type of facility; gas plant (GP) or gathering system (GS).
- EUB FACILITY CODE - the unique code assigned by the EUB which identifies the EUB facility to which the Facility Cost Centre is linked.

NOTE: IN ORDER TO AMEND THE EUB FACILITY REPORTED UNDER FIELD 2.1, THE EXISTING AC1 FORM MUST BE TERMINATED AND A NEW ACI FORM MUST BE SETUP.

2.2 **DESCRIPTION OF EUB FACILITY** - The name or other description that describes the EUB facility.

2.3 **FACILITY COST CENTRE CODE** - The numeric code assigned to the Facility Cost Centre:

- for existing Facility Cost Centres enter the Facility Cost Centre code assigned by the Department;
- for new Facility Cost Centres, i.e. compressing, gathering or processing systems, leave the field blank; the Department will assign a code;

2.4 **DESCRIPTION OF FACILITY COST CENTRE** - The name or other description that identifies the Facility Cost Centre.

2.5 **REMAINING USEFUL LIFE -** *The approved remaining useful life of the reserves served by the Facility Cost Centre. This is required if the AC1 form is being filed to register an initial setup or if the Department has approved changes to the remaining useful life. Changes to the remaining useful life, which are approved by the Department, will be effective the first day of the production year. If the AC1 is received after the May 15 deadline, the effective date of the change will be the first day of the next production year. Changes to the remaining useful life of the Facility Cost Centre will not be retroactive.*

2.6 **EFFECTIVE DATE -** The numeric year and month in which:

- the Facility Cost Centre first came into service, *if this is an initial setup; or*

2.7 **TERMINATION DATE -** The numeric year and month in which the Facility Cost Centre is terminated, *if the change is to terminate a Facility Cost Centre.*

2.8 **ASSOCIATED EUB FACILITY CODE -** If the facility is one for which the Department has assigned a *non-standard* facility code, enter the EUB code assigned to the facility with which it is associated *(not required for gathering systems or gas plants)*.

2.9 **PREVIOUS FACILITY COST CENTRE CODE -** If the AC1 form is submitted to change an existing Facility Cost Centre and the change involves either combining or separating registered facilities, enter the code(s) that were previously assigned to the Facility Cost Centre(s) involved. *(If the space provided on the form is not sufficient, attach a schedule to identify additional Facility Cost Centre codes.)*

2.10 **REPORTED EUB FACILITY CODE -** Indicate the alternate EUB facility codes *(if different from field 2.1)* within the network where Crown royalty is calculated. Completion of *field 2.10* will ensure that operating costs at the reported facility *(field 2.10)* are not recaptured. If no alternative facility exists this field should be left blank.

PART 3: CHANGE IN FACILITY COST CENTRE OPERATOR

3.1 **NEW FACILITY COST CENTRE OPERATOR ID -** The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the new operator of the Facility Cost Centre.

3.2 **NEW FACILITY COST CENTRE OPERATOR NAME -** The full name of the new operator of the Facility Cost Centre.

3.3 **EFFECTIVE DATE -** The numeric year and month when the new operator of the Facility Cost Centre took over.

PART 4: FACILITY COST CENTRE OWNERSHIP

4.1 **EFFECTIVE DATE -** The numeric year and month in which the Facility Cost Centre ownership *(setup, change or terminated)* is effective.

4.2 **CLIENT ID -** The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is an owner in the Facility Cost Centre *(for all owners in the Facility Cost Centre)*.

4.3 **FACILITY COST CENTRE OWNER NAME** - The full name of the person who is an owner of the Facility Cost Centre and whose client ID appears in *column 4.2*.

4.4 **% OWNERSHIP** - The percentage of the Facility Cost Centre that is owned by the owner identified in *fields 4.2 and 4.3 (total % ownership reported on each AC1 must be to five decimal places, and account for 100% of the Facility Cost Centre ownership)*.

For the 1994 production year only, the FCC operators are not required to complete Part 4 of the AC1 Form. However, this part must be completed for production year 1995 onwards to record the changes in the ownership percentage. Ownership changes during a year are not required to be reported to the Department during that year. Ownership percentage must be reported as at December 31 of the production year in which the changes occurred.

NOTE: IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF FIELD 4.3

PART 5: FACILITY COST CENTRE TYPE

5.1 **FACILITY COST CENTRE TYPE** - Check either COMPRESSING, GATHERING or PROCESSING to identify the type of Facility Cost Centre that is the subject of the AC1 form.

COMPRESSING includes only those facilities coded as COMPRESSOR.

GATHERING includes only those facilities coded as GATHERING SYSTEM.

PROCESSING includes those facilities coded as:

GAS PLANT
DEHYDRATOR
SEPARATOR
SALES LINE AFTER PLANT
LIQUID LINE
SULPHUR FACILITIES
REMELTER
PRILLER/SLATER

These are also referred to as processing subtypes.

5.2 **PROCESSING SUBTYPE** - The subtype of the processing facility.

PART 6: SHUT IN/REACTIVATION

SHUT IN

6.1 **SHUT IN** - Check this box only if the Facility Cost Centre is shut in for the entire year. Leave this box blank if Facility Cost Centre is active or reactivated in the year.

6.2 **EFFECTIVE YEAR** - The year in which the Facility Cost Centre was shut in.

REACTIVATION

6.2 **EFFECTIVE YEAR** - The year in which the Facility Cost Centre was reactivated.

24.2 Preparing an Annual Capital Cost Allowances Report for Production Years 1994, 1995 and 1996.

AC2-V1 FORM - CAPITAL COST ALLOWANCE

PURPOSE

Operators of Facility Cost Centres *(FCC Operators)* must use the AC2-V1 form to report:

a) changes in the allowable capital cost at a Facility Cost Centre over a production year;

b) calculation of Capital Cost Allowances for a Facility Cost Centre for a production year; *and*

c) allocation of the Capital Cost Allowances for a production year to the royalty clients at the Facility Cost Centre.

For b) and c), the FCC operator should submit the AC2-V1 form at December 31 of the production year.

A description of the business rules associated with determining changes to allowable capital costs and calculating Capital Cost Allowances is provided in *Sections 16.4-16.8.*

FULLY DEPRECIATED FCC

Facility Cost Centre (FCC) Operators must continue to file AC2 forms even after the RUL of the FCC becomes zero. As long as an FCC is active, AC2 forms are required to identify Capital Cost Allowance Distribution Percentages and Custom Processing Adjustment Factors for the FCC. Filing AC2 forms will also prevent operating cost recaptures for those royalty clients who have an ownership interest in the FCC.

TIMING

The Client Services Help Desk must receive a completed AC2-V1 form on or before April 15 of the year following the production year to which the form relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a AC2-V1 Form by its due date is replaced with a new penalty of $100 per month or part of a month until the form is received. If the form is not received, no capital cost allowance will be allocated to the Facility Cost Centre for the production year to which the form relates.

AMENDING AN ANNUAL CAPITAL COST ALLOWANCES REPORT

An amended AC2-V1 form must be completed in full just as with an initial AC2-V1 form.

AC2-V1 FORM - COMPLETION INSTRUCTIONS

PART 1: IDENTIFICATION

1.1 FACILITY CODE

- PROV. - the province in which the facility is located; Alberta (AB), British Columbia (BC), or Saskatchewan (SK).
- EUB FAC. TYPE - the type of facility; gas plant (GP) or gathering system (GS).
- EUB FACILITY CODE - the unique code assigned by the EUB which identifies the facility.

1.2 **FACILITY COST CENTRE CODE** - The Facility Cost Centre code assigned by the Department.

1.3 **DESCRIPTION OF FACILITY COST CENTRE** - The name or other description that identifies the Facility Cost Centre.

1.4 **FACILITY COST CENTRE OPERATOR ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is the operator of the Facility Cost Centre.

1.5 **FACILITY COST CENTRE OPERATOR NAME** - The full name of the person who is the operator of the Facility Cost Centre.

1.6 **PRODUCTION YEAR** - The production year to which the reported information applies.

1.7 **DATE PREPARED** - The numeric year, month and day on which the AC2-V1 form is prepared.

1.8 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.9 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: CAPITAL COST ALLOWANCE CALCULATION (AMOUNTS MUST BE TO THE NEAREST DOLLAR)

ALLOWABLE CAPITAL COSTS

2.1 **CUMULATIVE ALLOWABLE CAPITAL, JAN 1 OR______** — The cumulative allowable capital at the beginning of the year is either:

- the cumulative allowable capital at December 31 of the previous year, brought forward from the submission for that year; *or*
- the allowable capital and allowable overhead on construction, in the case of a new facility.

If the Facility Cost Centre started or resumed operations other than on January 1, enter the date of commencement or resumption in the space provided.

2.2 **ALLOWABLE CAPITAL COST, JAN 1 OR______** — The allowable capital cost at the beginning of the year is either:

- the allowable capital cost at the December 31 of the previous year, brought forward from the submission for that year; *or*
- the allowable capital and allowable overhead on construction, in the case of a new facility.

If the Facility Cost Centre started or resumed operations other than on January 1, enter the start or resume date in the space provided.

2.3 **CAPITAL ADDITIONS (CARRIED FROM PART 3)** - If the AC2-V1 form is for an existing facility, enter the total of ADDITIONS/DISPOSITIONS/RETIREMENTS recorded in *field 3.4*.

If the AC2-V1 form is for a new facility, enter only the capital additions/dispositions/retirements that occurred after the facility commenced operation. In this case, the total recorded in *field 3.4* will equal the sum of *field 2.2 ...plus... field 2.3*.

2.4 **CUMULATIVE ALLOWABLE CAPITAL, DEC 31 OR______** — The sum of cumulative allowable capital at January 1 *(or other)* shown in *field 2.1 ...plus...* capital additions shown in *field 2.3 (this field must be completed)*.

If facility operations are terminated before December 31, enter the date on which the facility terminated operations in the space provided.

2.5 **ALLOWABLE CAPITAL COST, BEFORE DEPRECIATION, DEC 31 OR___** — The sum of allowable capital cost at January 1 shown in *field 2.2 ...plus...* capital additions shown in *field 2.3*.

2.6 **DEPRECIATION ______/12** — Allowable Capital Cost December 31 Before Depreciation (*field 2.5*) *...divided by...* Remaining Useful Life of the Facility Cost Centre.

If the Facility Cost Centre started operations at other than January 1, or terminated operations at other than December 31 of the production year, enter the number of months of operation in the space provided (___/12) and multiply the product obtained in the above calculation by the resulting fraction *(e.g., 9/12)*.

2.7 **ALLOWABLE CAPITAL COST AFTER DEPRECIATION, DEC 31 OR______** — The sum of Allowable Capital Cost before depreciation, December 31 or___ shown in *field 2.5 ...minus...* Depreciation shown in *field 2.6*.

If facility operations are terminated before December 31, enter the date on which the facility terminated operations in the space provided.

RETURN ON AVERAGE CAPITAL

2.8 **AVERAGE CAPITAL** - The sum of (Allowable Capital Cost, January 1 or___ in *field 2.2 ...plus...* Allowable Capital Cost after depreciation, December 31 or___ in *field 2.7*) *...divided by...*2.

2.9 **LAND** - The original capital cost of the site on which the Facility Cost Centre is located. *(For allowable cost purposes, the value of land does not change.)*

2.10 **AVERAGE SPARE PARTS INVENTORY** - The sum of (spare parts inventory at the beginning of the period *...plus...* spare parts inventory at the end of the period) *...divided by...* 2.

2.11 **TOTAL** - The sum of Average Capital (*field 2.8*) *...plus...* Land (*field 2.9*) *...plus...* Average Spare Parts Inventory (*field 2.10*).

CAPITAL COST ALLOWANCE

2.12 **RETIREMENTS** – Enter the absolute (positive) amount for retirements (CODE "R") included in *field 3.3.*

2.13 **DEPRECIATION** - Enter the amount shown as Depreciation____/12 at *field 2.6.*

2.14 **RETURN ON AVERAGE CAPITAL______/12** — Total Average Capital (*field 2.11*) *...multiplied by...* 0.15 *(15% rate of return).*

If the Facility Cost Centre started operations at other than January 1, or terminated operations at other than December 31 of the production year, enter the number of months of operation in the space provided (___/12) and multiply the product obtained in the above calculation by the resulting fraction *(e.g., 9/12).*

2.15 **CAPITAL COST ALLOWANCE** - The sum of Retirement (*field 2.12) ...plus...*Depreciation Capital *(field 2.13) ...plus...* Return on Average Capital (*field 2.14*).

2.16 **REMAINING USEFUL LIFE (YRS)** Please indicate the remaining useful life of the Facility Cost Centre in years. FCC Operators must continue to file AC2 forms even after the remaining useful life of the FCC becomes zero, if the FCC is still active.

PART 3: CAPITAL ADDITIONS (AMOUNTS MUST BE TO THE NEAREST DOLLAR)

3.1 **ADDITIONS/DISPOSITIONS/RETIREMENTS** - A description of each allowable capital addition, disposition or retirement by significant category. Small additions should be grouped under the heading "miscellaneous."

If the AC2-V1 form is for a new facility, capital additions must indicate the descriptions of the capital shown as Cumulative Capital, January 1, or_____ in *field 2.1,* as well as additions, dispositions, and retirements after the commencement of the operation. If the space provided is not sufficient, attach a continuation page.

3.2 **TYPE** - For each item entered in *field 3.1,* identify the type of transaction as Addition (A), Disposition (D) or Retirement (R).

3.3 **AMOUNT OF ADDITIONS/DISPOSITIONS/RETIREMENTS** - Enter the actual cost of each Capital Addition or net book value of each Disposition or Retirement described in *field 3.1.* (Capital additions are positive. Dispositions and Retirements are negative).

3.4 **TOTAL** - Enter the sum of all of the allowable costs entered in *field 3.3,* including the allowable costs recorded on any attached schedule that may be required.

NOTE: PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF *FIELD 3.1*, IF APPLICABLE.

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

4.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the owner or designated royalty client to whom capital cost allowances is allocated.

4.2 **CLIENT NAME** - The full name of the owner or designated royalty client whose Client ID appears in *field 4.1.*

4.3 **CAPITAL COST ALLOWANCE DISTRIBUTIONS %** - The percentage of the Facility Cost Centre capital cost allowance that is allocated to each owner or designated royalty client identified in *field 4.1* and *field 4.2*, to five decimal places.

If the Facility Cost Centre has a Custom Processing Factor *(other than zero)*, the Capital Cost Allowance Distributions % must be reduced to take that factor into account.

4.4 **FACILITY CUSTOM PROCESSING ADJUSTMENT FACTOR (CPAF)** - Enter the Custom Processing Adjustment Factor calculated and published by the Department for the Facility Cost Centre (The factor is published as a percentage, to five decimal places, and must be directly transposed to this field). For Facility Cost Centres that became operational after 1992, the Facility Cost Centre's operator must identify the CPAF and attach supporting details (on CPAF form, see Appendix P) identifying the custom processed volumes by client and the total facility's throughput volumes. If there is no custom processing at the Facility Cost Centre, then the CPAF must be indicated as 0%.

NOTE: ALL EXCESS CAPACITY VOLUMES OF THE OWNERS WHO PAID CUSTOM PROCESSING FEES MUST BE INCLUDED TO DETERMINE CPAF %.

4.5 **TOTAL CAPITAL COST ALLOWANCE ALLOCATED (100%)** - Ensure that the total capital cost allowance allocation percentages, including the Facility Custom Processing Adjustment Factor, equals 100%.

NOTE: (1) IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF *FIELD 4.2*.

NOTE: (2) THE FOLLOWING ARITHMETIC EDITS WILL APPLY TO ALL AC2-V1 FORMS SUBMITTED FOR NEW FACILITY COST CENTRES AND EXISTING FACILITY COST CENTRES. EDIT FAILURE WILL RESULT IN A FULL FORM REJECTION.

NEW FACILITY COST CENTRES:

- *FIELDS 2.1 = 2.2*
- *FIELDS 2.4 = 2.1 + 2.3 = 2.5*
- *FIELDS 2.5 = 2.2 + 2.3 = 3.4*
- *FIELD 3.4 =* (the sum of the absolute value of all additions type (A) amounts ...*minus* ... the sum of the absolute value of all dispositions type (D) amounts ...*minus*... the sum of the absolute value of all retirements type (R) amounts)
- For new Facility Cost Centres, Field 2.3 will be accepted if it is numeric and positive. Also, a break down of the cumulative allowable capital (*Field 2.1*) must be reported in Part 3 as capital additions (with a type (A) in 3.2). Therefore, *Field 3.4* will equal the sum of *Field 2.1* and *Field 2.3* for new Facility Cost Centres.

NOTE: THIS DOES NOT APPLY TO NEW FACILITY COST CENTRES THAT WERE SET UP TO COMBINE/SEPARATE EXISTING FACILITY COST CENTRES.

EXISTING FACILITY COST CENTRES:

- *FIELD 2.3 = 3.4*
- *FIELD 3.4* will only equal *FIELD 2.3* for existing Facility Cost Centres

24.2.1 Preparing an Annual Capital Cost Allowance Report For Production Years 1997 and Onwards

AC2-V2 FORM - CAPITAL COST ALLOWANCE

ELECTRONIC SUBMISSION OF AC2

The functionality to submit and receive AC2 data electronically through the Electronic File Transfer process is available to clients. A copy of the Handbook on Electronic File Transfer of AC2 form is available on the Resource Development Internet site. The Handbook addresses the AC2 electronic file transfer business and technical processes, business rules, administrative, technical requirements and validation edit details for electronic filing. It is located in the Resource Development website:

http://resdev.gov.ab.ca/room/elecdata/handbook/mris/handbook.htm

This filing option is non mandatory. However, facility operators who wish to submit the AC2 form electronically, either for themselves or through contract operators and service providers must comply with the business rules stated in the Handbook.

All electronic files received by midnight of the 15th of each month will be processed and reflected in that month's issue of the Gas Royalty Invoice. There will be no guarantee for electronic files received between the 16th of the month and the start day of the invoice cycle that they will be processed for that invoice run.

Process Overview

- Department will accept either manual or direct electronic receipt of AC2 with Industry direct electronic data submission costs to be born by Industry.
- All Royalty Clients have the option of submitting the AC2 data electronically. If a company chooses to submit the AC2 form in this manner, it must do so for all production years.
- For electronic AC2 data submission by Industry, the Department will transmit data back electronically.
- For electronic submission of form data:
  - Industry will transfer an encrypted file housing AC2 data via File Transfer Protocol (FTP) to the Department.
  - Department will process file data nightly (except during invoice run – 5 days).
  - Department will send email to FCC operator (the individual responsible for submitting AC2 form) to allow operator to check file status in company output directory on the Department's FTP site.
  - Output directory will contain either a Turnaround Document (for accepted data) or Rejection Notices (for rejected data).

Industry Requirement Overview

Acquire the encryption package PGP. Information may be acquired by accessing web site WWW.NAI.COM. This software encrypts file, limiting file access to those with the appropriate decryption key.

(a) Be capable of FTP transmission.

(b) Provide the Department with a public encryption key, enabling Department to encrypt Industry Output files (turnaround documents/rejection notices) and verify their Industry signature on Input to Department.

(c) Obtain user ID and password from the Department, which will enable Industry Client to access its directories on the Department's FTP server.

(d) Obtain a public encryption key from the Department to enable Industry Client to encrypt files to be sent to the Department and verify the origin of any data files placed in their Output directory.

(e) FTP the PGP encrypted file. File must be in Department Defined Format (TBA) and properly signed.

(f) Access Output directory to retrieve Industry Output files (turnaround documents/rejection notices). These files will be dated and named appropriately for easy identification.

(g) Decrypt the Industry Output files using private key.

PURPOSE

Operators of Facility Cost Centres *(FCC Operators)* must use the AC2-V2 form to report:

a) changes in the allowable capital cost at a Facility Cost Centre over a production year;

b) calculation of Capital Cost Allowances for a Facility Cost Centre for a production year; *and*

c) allocation of the Capital Cost Allowances for a production year to the royalty clients at the Facility Cost Centre.

For b) and c), the FCC operator should submit the AC2-V2 form at December 31 of the production year.

A description of the business rules associated with determining changes to allowable capital costs and calculating Capital Cost Allowances is provided in *Sections 16.4-16.8.*

FULLY DEPRECIATED FCC

Facility Cost Centre (FCC) Operators must continue to file AC2 forms even after the RUL of the FCC becomes zero. As long as an FCC is active, AC2 forms are required to identify Capital Cost Allowance Distribution Percentages and Custom Processing Adjustment Factors for the FCC. Filing AC2 forms will also prevent operating cost recaptures for those royalty clients who have an ownership interest in the FCC.

NOTE: OPERATING COST WILL NOT BE ALLOWED AS A DEDUCTION ON RAW GAS SALES THAT ARE ELIGIBLE FOR 80% GAS REFERENCE PRICE VALUATION.

TIMING

A completed AC2-V2 form (Parts 1 to 5) must be received by the Client Services Help Desk on or before April 15 of the year following the production year to which the form relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a AC2-V2 Form by its due date is replaced with a penalty of $100 per month or part of a month until the form is received. If the form is not received, no capital cost allowance will be allocated to the Facility Cost Centre for the production year to which the form relates.

AMENDING AN ANNUAL CAPITAL COST ALLOWANCES REPORT

An amended AC2-V2 form must be completed in full same as with an initial AC2-V2 form.

AC2-V2 FORM - COMPLETION INSTRUCTIONS

PART 1: IDENTIFICATION

1.1 FACILITY CODE

- PROV. - the province in which the facility is located; Alberta (AB), British Columbia (BC), or Saskatchewan (SK).
- EUB FAC. TYPE - the type of facility; gas plant (GP) or gathering system (GS).
- EUB FACILITY CODE - the unique code assigned by the EUB which identifies the facility.

1.2 **FACILITY COST CENTRE CODE** - The Facility Cost Centre code assigned by the Department.

1.3 **DESCRIPTION OF FACILITY COST CENTRE** - The name or other description that identifies the Facility Cost Centre.

1.4 **FACILITY COST CENTRE OPERATOR ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is the operator of the Facility Cost Centre.

1.5 **FACILITY COST CENTRE OPERATOR NAME** - The full name of the person who is the operator of the Facility Cost Centre.

1.6 **PRODUCTION YEAR** - The production year to which the reported information applies.

1.7 **DATE PREPARED** - The numeric year, month and day on which the AC2-V2 form is prepared.

1.8 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.9 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: CAPITAL COST ALLOWANCE CALCULATION (amounts must be to the nearest dollar)

ALLOWABLE CAPITAL COSTS

2.1 **CUMULATIVE ALLOWABLE CAPITAL, JAN 1 OR_________** — The cumulative allowable capital at the beginning of the year is either:

- the cumulative allowable capital at December 31 of the previous year, brought forward from the submission for that year; *or*
- the allowable capital and allowable overhead on construction, in the case of a new facility.

If the Facility Cost Centre started or resumed operations other than on January 1, enter the date of commencement or resumption in the space provided.

2.2 **ALLOWABLE CAPITAL COST, JAN 1 OR__________** — The allowable capital cost at the beginning of the year is either:

- the allowable capital cost at December 31 of the previous year, brought forward from the submission for that year; *or*
- the allowable capital and allowable overhead on construction, in the case of a new facility.

If the Facility Cost Centre started or resumed operations other than on January 1, enter the start or resume date in the space provided.

2.3 **CAPITAL ADDITIONS (CARRIED FROM PART 3)** - If the AC2-V2 form is for an existing facility, enter the total of ADDITIONS/DISPOSITIONS/RETIREMENTS recorded in *field 3.4*.

If the AC2-V2 form is for a new facility, enter only the capital additions/dispositions/retirements that occurred after the facility commenced operation. In this case, the total recorded in *field 3.4* will equal the sum of *field 2.2 ...plus... field 2.3*.

2.4 **CUMULATIVE ALLOWABLE CAPITAL, DEC 31 OR__________** — The sum of cumulative allowable capital at January 1 *(or other)* shown in *field 2.1 ...plus...* capital additions shown in *field 2.3 (this field must be completed)*.

If facility operations are terminated before December 31, enter the date on which the facility terminated operations in the space provided.

2.5 **ALLOWABLE CAPITAL COST, BEFORE DEPRECIATION, DEC 31 OR _____** — The sum of allowable capital cost at January 1 shown in *field 2.2 ...plus...* capital additions shown in *field 2.3*.

2.6 **DEPRECIATION ____________/12** — Allowable Capital Cost December 31 Before Depreciation (*field 2.5*) *...divided by...* Remaining Useful Life of the Facility Cost

If the Facility Cost Centre started operations at other than January 1, or terminated operations at other than December 31 of the production year, enter the number of months of operation in the space provided (___/12) and multiply the product obtained in the above calculation by the resulting fraction *(e.g., 9/12)*.

2.7 **ALLOWABLE CAPITAL COST AFTER DEPRECIATION, DEC 31 OR ________** — The sum of Allowable Capital Cost before depreciation, December 31 or___ shown in *field 2.5 ...minus...* Depreciation shown in *field 2.6*.

If facility operations are terminated before December 31, enter the date on which the facility terminated operations in the space provided.

RETURN ON AVERAGE CAPITAL

2.8 **AVERAGE CAPITAL** - The sum of (Allowable Capital Cost, January 1 or___ in *field 2.2 ...plus...* Allowable Capital Cost after depreciation, December 31 or____in *field 2.7*) *...divided by...*2.

2.9 **LAND** - The original capital cost of the site on which the Facility Cost Centre is located. *(For allowable cost purposes, the value of land does not change.)*

2.10 **AVERAGE SPARE PARTS INVENTORY** - The sum of (spare parts inventory at the beginning of the period *...plus...* spare parts inventory at the end of the period) *...divided by...* 2.

2.11 **TOTAL** - The sum of Average Capital (*field 2.8*) *...plus...* Land (*field 2.9*) *...plus...* Average Spare Parts Inventory (*field 2.10*).

CAPITAL COST ALLOWANCE

2.12 **RETIREMENTS** - Enter the absolute (positive) amount for retirements (CODE "R") included in *field 3.3.*

2.13 **DEPRECIATION** - Enter the amount shown as Depreciation____/12 at *field 2.6.*

2.14 **RETURN ON AVERAGE CAPITAL__________/12** — Total Average Capital (*field 2.11*) *...multiplied by...* 0.15 *(15% rate of return).*

If the Facility Cost Centre started operations at other than January 1, or terminated operations at other than December 31 of the production year, enter the number of months of operation in the space provided (___/12) and multiply the product obtained in the above calculation by the resulting fraction *(e.g., 9/12).*

2.15 **CAPITAL COST ALLOWANCE** - The sum of Retirement (*field 2.12*) *...plus...*Depreciation Capital (*field 2.13*) *...plus...* Return on Average Capital (*field 2.14*).

2.16 **REMAINING USEFUL LIFE** (Years) Indicate the remaining useful life of the Facility Cost Centre in years. FCC operators must continue to file AC2 forms even after the remaining useful life of the FCC becomes zero, if the FCC is still active.

PART 3: CAPITAL ADDITIONS (AMOUNTS MUST BE TO THE NEAREST DOLLAR)

3.1 **ADDITIONS/DISPOSITIONS/RETIREMENTS** - A description of each allowable capital addition, disposition or retirement by significant category. Small additions should be grouped under the heading "miscellaneous."

If the AC2-V2 form is for a new facility, capital additions must indicate the descriptions of the capital shown as Cumulative Capital, January 1, or______in *field 2.1,* as well as additions, dispositions, and retirements after the commencement of the operation. If the space provided is not sufficient, attach a continuation page.

3.2 **TYPE** - For each item entered in *field 3.1*, identify the type of transaction as Addition (A), Disposition (D) or Retirement (R).

3.3 **AMOUNT OF ADDITIONS/DISPOSITIONS/RETIREMENTS** - Enter the actual cost of each Capital Addition or net book value of each Disposition or Retirement described in *field 3.1.* (Capital additions are positive. Dispositions and Retirements are negative).

3.4 **TOTAL** - Enter the sum of all of the allowable costs entered in *field 3.3,* including the allowable costs recorded on any attached schedule that may be required.

NOTE: PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF *FIELD 3.1*, IF APPLICABLE.

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

4.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the owner or designated royalty client to whom capital cost allowances is allocated.

4.2 **CLIENT NAME** - The full name of the owner or designated royalty client whose Client ID appears in *field 4.1.*

4.3 **CAPITAL COST ALLOWANCE DISTRIBUTIONS %** - The percentage of the Facility Cost Centre capital cost allowance that is allocated to each owner or designated royalty client identified in *field 4.1* and *field 4.2*, to five decimal places.

If the Facility Cost Centre has a Custom Processing Factor *(other than zero)*, the Capital Cost Allowance Distributions % must be reduced to take that factor into account.

4.4 **CUSTOM PROCESSING ADJUSTMENT FACTOR %(CARRIED FROM PART 5)**- Enter the Custom Processing Adjustment Factor recorded in *field 5.7*.

4.5 **TOTAL CAPITAL COST ALLOWANCE ALLOCATED (100%)** - Ensure that the total capital cost allowance allocation percentages, including the Facility Custom Processing Adjustment Factor, equals 100%.

NOTE: PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF *FIELD 4.2*, IF APPLICABLE.

PART 5: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

5.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the royalty client whose volumes are subject to custom processing fees at the Facility Cost Centre.

5.2 **CLIENT NAME** - The full name of the custom user whose Client ID appears in *field 5.1*.

5.3 **UNIT** - The unit of measure (10^3/m^3/tonnes- please check (✓) one) of the Custom Volumes reported in *field 5.4* and *field 5.5* and the Total Facility Cost Centre Throughput reported in *field 5.6*. .

5.4 **CUSTOM VOLUMES** - The Facility Cost Centre inlet volume of gas and gas products custom processed for the Custom User identified in *field 5.1* and *field 5.2*. The Custom volumes must also include Excess Capacity Volumes of the owners who are charged Custom Processing Fees. If the Facility Cost Centre has more than one product, please convert the volumes to Gas Equivalent Volumes. To calculate the Gas Equivalent Volume for each custom processed product, multiply the product volume in its base unit (10^3m^3/m^3/tonnes) by its Gas Equivalent Factor. The Gas Equivalent Factors are provided in *Section 16.13.1*. Sum up each product's Gas Equivalent Volume to determine the total Gas Equivalent Volume for each royalty client.

5.5 **TOTAL CUSTOM VOLUMES** - The sum of all Custom Volumes entered in *field 5.4*.

5.6 **TOTAL FACILITY COST CENTRE THROUGHPUT** - The total volume of gas and gas products compressed, gathered and/or processed at the Facility Cost Centre. Please convert the volumes to Gas Equivalent Volumes if the Facility Cost Centre processes gas and gas products.

5.7 **CUSTOM PROCESSING ADJUSTMENT FACTOR %** - The Total Custom Volumes (*field 5.5)* ...divided by ... the Total Facility Cost Centre Throughput (*field 5.6)*.......multiplied by 100.

The Custom Processing Adjustment Factor (CPAF) is calculated as a percentage to five decimal places. The CPAF must be recalculated every production year. If there is no custom processing at the Facility Cost Centre, then the CPAF must be indicated as 0.00000%. Enter the CPAF percentage in field 4.4.

NOTE: (1) IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S)ARE ATTACHED", ON THE BOTTOM LINE OF *FIELD 4.2*.

NOTE: (2) THE FOLLOWING ARITHMETIC EDITS WILL APPLY TO ALL AC2-V2 FORMS SUBMITTED FOR NEW FACILITY COST CENTRES AND EXISTING FACILITY COST CENTRES. EDIT FAILURE WILL RESULT IN A FULL FORM REJECTION.

NEW FACILITY COST CENTRES:

- *Fields 2.1 = 2.2*
- *Fields 2.4 = 2.1 + 2.3 = 2.5*
- *Fields 2.5 = 2.2 + 2.3 = 3.4*
- *Field 3.4 =* (the sum of the absolute value of all additions type (A) amounts ...*minus* ... the sum of the absolute value of all dispositions type (D) amounts ...*minus*... the sum of the absolute value of all retirements type (R) amounts)
- For new Facility Cost Centres, *Field 2.3* will be accepted if it is numeric and positive. Also, a break down of the cumulative allowable capital (*Field 2.1*) must be reported in Part 3 as capital additions (with a type (A) in *3.2*). Therefore, *Field 3.4* will equal the sum of *Field 2.1* and *Field 2.3* for new Facility Cost Centres.

NOTE: THIS DOES NOT APPLY TO NEW FACILITY COST CENTRES THAT WERE SET UP TO COMBINE/SEPARATE EXISTING FACILITY COST CENTRES.

EXISTING FACILITY COST CENTRES:

- *Field 2.3 = 3.4*
- *Field 3.4* will only equal *Field 2.3* for existing Facility Cost Centres

24.3 Preparing an Annual Capital Cost Allowance Reallocation

AC3 FORM - CAPITAL COST ALLOWANCE REALLOCATIONS

PURPOSE

A royalty client or owner who has been allocated Capital Cost Allowance at a Facility Cost Centre on the AC2 form may make a further allocation of that Capital Cost Allowance to other royalty clients. Royalty clients or owners must use the AC3 form to reallocate Capital Cost Allowance at a Facility Cost Centre.

A description of the business rules associated with reallocating Capital Cost Allowance is provided in *Section 16.8.1*.

TIMING

A completed AC3 form must be received by the Client Services Helpdesk, on or before May 15 of the year following the production year to which the report relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 onwards, the penalty of $1000 per month or part of a month for failing to file a AC3 Form by its due date is removed. If the form is not submitted, capital re-allocation will not be made.

AMENDING AN ALLOWABLE CAPITAL REALLOCATIONS

An amended AC3 form must be completed in full just as with an initial AC3 form.

AC3 FORM - COMPLETION INSTRUCTIONS

PART 1: IDENTIFICATION

1.1 **FACILITY CODE**

- PROV. - the province in which the facility is located; Alberta (AB), British Columbia (BC), or Saskatchewan (SK).
- EUB FAC. TYPE - the type of facility; gas plant (GP) or gathering system (GS).
- EUB FACILITY CODE - the unique code assigned by the EUB that identifies the facility.

1.2 **FACILITY COST CENTRE CODE** - The numeric code assigned to the Facility Cost Centre. Enter the Facility Cost Centre code assigned by the Department.

1.3 **DESCRIPTION OF FACILITY COST CENTRE** - The name or other description that identifies the Facility Cost Centre.

1.4 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is making a reallocation of his Capital Cost Allowance.

1.5 **CLIENT NAME** - The full name of the person who is making a reallocation of his Capital Cost Allowance.

1.6 **PRODUCTION YEAR** - The production year to which the reported information applies.

1.7 **DATE PREPARED** - The numeric year, month and day on which the AC3 form is prepared.

1.8 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.9 **TELEPHONE** - The telephone number, including area code, of the contact person.

PART 2: CAPITAL COST ALLOWANCE REALLOCATIONS

2.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person to whom the reallocation is made.

2.2 **CLIENT NAME** - The full name of the person to whom the reallocation of Capital Cost Allowance is made.

2.3 **PERCENTAGE OF ORIGINAL ALLOCATION** - The percentage of the Capital Cost Allowance originally allocated that is reallocated to each client identified in *field 2.1* to five decimal places *(e.g., if Company A receives the original AC2 allocation of 10% and wishes to reallocate 50% of it to Company B, the percentage shown on the AC3 from Company A to Company B will be 50%).*

24.4 Preparing an Annual Allowable Operating Costs Report

AC4 FORM - ALLOWABLE COSTS - OPERATING COSTS

ELECTRONIC SUBMISSION OF AC4

The functionality to submit and receive AC4 data electronically through the Electronic File Transfer process is now available to clients. A copy of the Handbook on Electronic File Transfer of AC4 form is available on the Resource Development Internet site. The Handbook addresses the AC4 electronic file transfer business and technical processes, business rules, administrative, technical requirements and validation edit details for electronic filing. It is located in the Resource Development website:

http://resdev.gov.ab.ca/room/elecdata/handbook/mris/handbook.htm

This filing option is non mandatory. However, facility operators who wish to submit the AC4 form electronically, either by themselves or through contract operators and service providers must comply with the business rules stated in the Handbook.

All electronic files received by midnight of the 15th of each month will be processed and reflected in that month's issue of the Gas Royalty Invoice. There will be no guarantee for electronic files received between the 16th of the month and the start day of the invoice cycle that they will be processed for that invoice run.

Process Overview

- Department will accept either manual or direct electronic receipt of AC4 data, with Industry direct electronic data submission costs to be born by Industry.
- All Royalty Clients have the option of submitting the AC4 data electronically. If a company chooses to submit the AC4 form in this manner, it must do so for all production years.
- For electronic AC4 data submission by Industry, the Department will transmit data back electronically.
- For electronic submission of form data:
    - Industry will transfer an encrypted file housing AC4 data via File Transfer Protocol (FTP) to the Department.
    - Department will process file data nightly (except during invoice run – 5 days).
    - Department will send email to FCC operator (the individual responsible for submitting AC4 form) to allow operator to check file status in company output directory on the Department's FTP site.
    - Output directory will contain either a Turnaround Document (for accepted data) or Rejection Notices (for rejected data).

Industry Requirement Overview

Acquire the encryption package PGP. Information may be acquired by accessing web site WWW.NAI.COM. This software encrypts file, limiting file access to those with the appropriate decryption key.

(a) Be capable of FTP transmission.
(b) Provide the Department with a public encryption key, enabling Department to encrypt Industry Output files (turnaround documents/rejection notices) and verify their Industry signature on Input to Department.
(c) Obtain user ID and password from the Department, which will enable Industry Client to access its directories on the Department's FTP server.
(d) Obtain a public encryption key from the Department to enable Industry Client to encrypt files to be sent to the Department and verify the origin of any data files placed in their Output directory.
(e) FTP the PGP encrypted file. File must be in Department Defined Format (TBA) and properly signed.
(f) Access Output directory to retrieve Industry Output files (turnaround documents/rejection notices). These files will be dated and named appropriately for easy identification.
(g) Decrypt the Industry Output files using private key.

PURPOSE

An operator of a Designated Facility, or an operator of an associated Facility Cost Centre tied to the Designated Facility *(refer to Appendix I)* is required to provide annual reporting to the Department describing the allowable operating costs of the Facility Cost Centre for each year. The AC4 form must be used to report annual allowable operating costs to the Department.

NOTE: **An operator of a Plant Type Facility is not required to provide annual operating cost information to the Department.**

A description of the business rules associated with reporting annual allowable operating costs is provided in *Section 16.1.1*.

TIMING

The Client Services Help Desk must receive a completed AC4 form, on or before March 31 of the year following the production year to which the form relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a AC4 Form by its due date is replaced with a new penalty of $1000 per year. If the form is not submitted, no operating costs for that Facility Cost Centre will be used for the calculation of the UOCR for the following year.

AMENDING AN OPERATING COSTS REPORT

An amended AC4 form must be completed in full just as with an initial AC4 form.

AC4 FORM - COMPLETION INSTRUCTIONS

1.1 **FACILITY CODE**

- **PROV.** - the province in which the facility is located; Alberta (AB), British Columbia (BC), or Saskatchewan (SK).
- **EUB FAC. TYPE** - the type of facility; gas plant (GP) or gathering system (GS).
- **EUB FACILITY CODE** - the unique code assigned by the EUB which identifies the facility.

1.2 **FACILITY COST CENTRE CODE** - The Facility Cost Centre code assigned by the Department.

1.3 **DESCRIPTION OF FACILITY COST CENTRE** - The name or other description that identifies the Facility Cost Centre.

1.4 **FACILITY COST CENTRE OPERATOR ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the person who is the operator of the Facility Cost Centre.

1.5 **FACILITY COST CENTRE OPERATOR NAME** - The full name of the person who is the operator of the Facility Cost Centre.

1.6 **PRODUCTION YEAR** - The production year to which the reported information applies.

1.7 **DATE PREPARED** - The numeric year, month and day on which the AC4 form is prepared.

1.8 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.9 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: ALLOWABLE OPERATING COSTS (AMOUNTS MUST BE TO THE NEAREST DOLLAR)

2.1 **ALLOWABLE OPERATING COSTS** - The actual allowable operating costs incurred during the year at the Designated Facility Operating Cost Centre that is the subject of the report. Costs must be reported under each of the 11 line items described. Any costs that do not relate to the 11 line items should be reported in *fields 2.2 and 2.3*. Note: to facilitate administrative simplicity, the Department will accept allowable operating costs as being those paid in the year rather than for the year unless this procedure is judged to significantly disadvantage the Crown. The Executive Director, Gas Royalty Operations is the sole judge of any questions pertaining to the interpretation and application of this procedure.

2.2 **OTHER ALLOWABLES (DESCRIPTION)** - A description of other allowable costs *(other than those shown in field 2.1 above)* incurred during the year at the Designated Facility Operating Cost Centre, by major category. This field will also be used to record the Department's audit adjustments for prior production years and to report a gain on disposal of capital assets.

2.3 **OTHER ALLOWABLES (ACTUAL OPERATING COSTS)** - Enter the actual other allowable operating costs paid during the year on the same line as the related description in *field 2.2*. Note: to facilitate administrative simplicity, the Department will accept other allowable operating costs as being those paid in the year rather than for the year unless this procedure is judged to significantly disadvantage the Crown. The Executive Director, Gas Royalty Operations is the sole judge of any questions pertaining to the interpretation and application of this procedure.

2.4 **DIRECT ALLOWABLE OPERATING COSTS** - Enter the sum of actual costs paid and reported in line-items 1 through 11 of *field 2.1 ...plus...* actual costs incurred and reported in *field 2.3*.

2.5 **OVERHEAD______%** - Overhead is calculated at 10% of *Direct Allowable Operating Costs* reported in *field 2.4*.

2.6 **DIRECT ALLOWABLE OPERATING COSTS AND OVERHEAD** - The sum of Direct Allowable Operating Costs *(field 2.4) ...plus...* Overhead *(field 2.5)*.

2.7 **WORKING CAPITAL ALLOWANCE** - The product of Direct Allowable Operating Costs *(field 2.6) ...multiplied by...* 0.025.

2.8 **TOTAL ALLOWABLE OPERATING COSTS** - The sum of Direct Allowable Operating Costs and Overhead *(field 2.6) ...plus...* Working Capital Allowance *(field 2.7)*.

24.5 Preparing an Annual Custom Processing Fees Paid Report For Production Years 1994, 1995 and 1996

AC5-V1 FORM - ALLOWABLE COSTS - CUSTOM PROCESSING FEES PAID

PURPOSE

A royalty client who has paid for compressing, gathering or processing gas and gas products on a *fee-for-service* basis must claim a Custom Processing Allowance on the gas and gas products (including fees associated with freehold, purchased and out-of-province volumes). Royalty clients must use the AC5-V1 form to report custom processing fees paid in order to claim Custom Processing Allowance.

A description of the business rules associated with the annual Crown share of Custom Processing Allowance is provided in *Section 16.16*.

NOTE: •CUSTOM FEES WILL NOT BE ALLOWED AS A DEDUCTION ON RAW GAS SALES THAT ARE ELIGIBLE FOR 80% GAS REFERENCE PRICE VALUATION. HOWEVER AC5 MUST BE SUBMITTED SHOWING FEES PAID ON RAW GAS SALES THROUGHPUT VOLUMES, IF APPLICABLE.

•IF A CUSTOM PROCESSING FEE IS CLAIMED AT A FACILITY WHERE THERE IS NO VOLUME ALLOCATION THROUGH EITHER OAS OR RMF2, THE CUSTOM PROCESSING FEE WILL BE DISALLOWED.

•AC5 FORM MUST BE SUBMITTED TO REPORT ALL FEES PAID FOR COMPRESSING, GATHERING OR PROCESSING OF GAS AND GAS PRODUCTS, WITHOUT EXCEPTION.

TIMING

A completed AC5-V1 form must be received by the Client Services Help Desk, by May 15 of the year following the production year to which the report relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a AC5-V1 Form by its due date is replaced with a penalty of $100 per month or part of a month until the form is received. If the form is not submitted, no custom processing allowance will be given for the production year to which the form relates. Also, operating costs will be recaptured if the royalty client does not have ownership interest in the Facility Cost Centre, and there have been no reported custom processing fees on the AC5 form.

AMENDING A CUSTOM PROCESSING FEES PAID REPORT

An amended AC5-V1 form must be completed in full same as with an initial AC5-V1 form.

PART 1: IDENTIFICATION

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client.

1.3 **PRODUCTION YEAR** - The production year to which the reported information applies.

1.4 **DATE PREPARED** - The numeric year, month and day on which the AC5-V1 form is prepared.

1.5 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: CUSTOM PROCESSING FEES PAID

NOTE: USE THIS SECTION OF THE FORM TO REPORT ELIGIBLE CUSTOM PROCESSING FEES PAID WHERE THE ROYALTY CLIENT HAS NO OWNERSHIP INTEREST IN ANY OF THE FACILITY COST CENTRES INVOLVED (I.E., COMPRESSING, GATHERING OR PROCESSING).

2.1 **CUSTOM PROCESSING FEE PAID** - The actual amount of the custom processing fee paid for services at the facility identified in *field 2.2.* The amount must be to the nearest dollar.

2.2 **EUB FACILITY PROV** - The province in which the facility is located; Alberta (AB), British Columbia (BC) or Saskatchewan (SK) **FAC. TYPE** - The type of facility; gas plant (GP) or gathering system (GS). **CODE** - The unique code assigned by the EUB which identifies the facility.

OFFICIAL DECLARATION

2.3 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the royalty client for whom the official declaration is made.

2.4 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field* 2.3.

2.5 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field* 2.3.

2.6 **DATE** - The date on which the authorized signing officer signed the official declaration.

NOTE: IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF FIELD 2.1.

PART 3: CUSTOM PROCESSING FEES PAID

NOTE: (1) USE THIS SECTION OF THE FORM TO REPORT ELIGIBLE CUSTOM PROCESSING FEES PAID WHERE THE ROYALTY CLIENT MAY BE AN OWNER IN SOME OF THE FACILITY COST CENTRES INVOLVED, AND IS CUSTOM PROCESSING THROUGH OTHERS. FOR EXAMPLE, A ROYALTY CLIENT MAY HAVE AN OWNERSHIP INTEREST IN A GATHERING SYSTEM AND IS A CUSTOM USER AT A COMPRESSING AND PROCESSING FACILITY. THE FEE PAID MAY RELATE TO ONE OR MORE OF THE COMPRESSING, GATHERING OR PROCESSING SERVICES COVERED BY THE UOCR FOR THE FACILITY. A DESCRIPTION OF THE ELIGIBLE CUSTOM PROCESSING FEES FOR COMPRESSING, GATHERING AND PROCESSING FACILITIES IS PROVIDED IN *SECTION 16.16.*

(2) IF A ROYALTY CLIENT HAS OWNERSHIP INTEREST IN SOME **FUNCTIONAL UNITS** (FACILITY COST CENTRES) OF AN EUB FACILITY AND IS A CUSTOM USER AT SIMILAR FUNCTIONAL UNITS OF THE SAME EUB FACILITY, THE ROYALTY CLIENT MAY SUBMIT A WRITTEN REQUEST TO THE DEPARTMENT REQUESTING THE MONTHLY OPERATING COSTS IN LIEU OF RECEIVING CUSTOM PROCESSING FOR THE EUB FACILITY. THE WRITTEN REQUEST MUST INCLUDE SUPPORTING DOCUMENTATION THAT PROVIDES EVIDENCE THAT THEY ARE DISADVANTAGED DUE TO OPERATING COST RECAPTURES EXCEEDING THE CUSTOM PROCESSING FEES PAID IN THE PRODUCTION YEAR. ONCE APPROVED, IN THE SUBSEQUENT PRODUCTION YEARS, THE CROWN WILL CONTINUE TO RECOGNIZE AN OPERATING COST DEDUCTION IN LIEU OF CUSTOM PROCESSING FOR THE FACILITY. NO FURTHER CUSTOM PROCESSING FEES WILL BE RECOGNIZED AT THE FACILITY BY THE CROWN. HOWEVER, ROYALTY CLIENTS MUST CONTINUE TO SUBMIT AN AC5 FORM PROVIDING CUSTOM PROCESSING FEES AND VOLUMES FOR THAT FACILITY TO THE DEPARTMENT ON AN ANNUAL BASIS.

(3) IF A ROYALTY CLIENT HAS OWNERSHIP INTEREST IN A FACILITY COST CENTRE AND IS ALSO PAYING CUSTOM PROCESSING FEES FOR PROCESSING EXCESS VOLUMES AT THE SAME FACILITY COST CENTRE, THEN:

- THE ROYALTY CLIENT WILL REPORT IN FIELD 3.2 THE FULL CUSTOM PROCESSING FEES. IN FIELD 3.4 THE **EXCESS CAPACITY VOLUMES** REPORTED SHOULD BE 0.1 $10^3M^3/M^3$/TONNES. THIS WILL ENABLE A ROYALTY CLIENT TO CLAIM THE **EXCESS CAPACITY FEE** WITH ONLY A MINIMAL OPERATING COST RECAPTURE. THE REASON UOCR WILL NOT BE RECAPTURED IS THAT THE EXCESS CAPACITY CHARGE IS INTENDED TO COVER THE CAPITAL AND PROFIT PORTION OF CUSTOM PROCESSING AND THEREFORE HAS NO OPERATING EXPENSE COMPONENT FROM WHICH UOCR SHOULD BE DISALLOWED. IN NO CASE IS A ROYALTY CLIENT TO RECEIVE DUPLICATEUOCR RECOGNITION.

3.1 **EUB FACILITY PROV** - The province in which the facility is located; Alberta (AB), British Columbia (BC) or Saskatchewan (SK) **FAC. TYPE** - The type of facility; gas plant (GP) or gathering system (GS). **CODE** - The unique code assigned by the EUB which identifies the facility.

3.2 **CUSTOM PROCESSING FEE PAID** - The actual amount of the custom processing fee paid for services at the facility identified in *field 3.1.* The amount is not required to be broken down for gas and gas products. The amount must be to the nearest dollar.

PRODUCTS/ VOLUMES DERIVED - report the product code and volume of gas and gas products obtained at the outlet of the facility at which the custom processing was done.

3.3 **PRODUCT CODE** - The product code that identifies the product volume reported in *field 3.4*, as recorded on the Owner Activity Statement for the facility at which the volumes were processed.

3.4 **VOLUME** - The volume of gas *(in 10^3m^3)* and gas products *(in m^3 or tonnes)* obtained at the outlet of the facility for which the fee recorded in *field 3.2* was paid.

3.5 **CUSTOM SERVICES PAID** - A checkmark *( )* must be placed in the field or fields that describe the custom processing services for which the fee recorded in *field 3.2* were paid. For every product listed in *field 3.3*, a corresponding checkmark must be placed in *field 3.5*. If it is left blank, the calculation will default to using the total unit operating cost (UOCR) at the EUB facility as operating cost recovery.

NOTE: IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF FIELD 3.1.

OFFICIAL DECLARATION

3.6 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer of the royalty client for whom the official declaration is made. The form will be rejected if this is left blank.

3.7 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field* 3.6.

3.8 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field* 3.6.

3.9 **DATE** - The date on which the authorized signing officer signed the official declaration.

24.5.1 Preparing an Annual Custom Processing Fees Paid Report for Production Years 1997 and Onwards

AC5-V2 FORM - ALLOWABLE COSTS - CUSTOM PROCESSING FEES PAID

PURPOSE

A royalty client who has paid for compressing, gathering or processing gas and gas products on a *fee-for-service* basis must claim a Custom Processing Allowance on the gas and gas products (including fees associated with freehold, purchased and out-of-province volumes). Royalty clients must use the AC5-V2 form to report custom processing fees paid in order to claim Custom Processing Allowance.

A description of the business rules associated with the annual Crown share of Custom Processing Allowance is provided in *Section 16.16*.

NOTE:

- CUSTOM FEES WILL NOT BE ALLOWED AS A DEDUCTION ON RAW GAS SALES THAT ARE ELIGIBLE FOR 80% GAS REFERENCE PRICE VALUATION. HOWEVER, AC5 MUST BE SUBMITTED SHOWING FEES PAID ON RAW GAS SALES THROUGHPUT VOLUMES IF APPLICABLE.
- IF CUSTOM PROCESSING FEE IS CLAIMED AT A FACILITY WHERE THERE IS NO VOLUME ALLOCATION THROUGH EITHER OAS OR RMF2, THE CUSTOM PROCESSING FEE WILL BE DISALLOWED.
- AC5 FORM MUST BE SUBMITTED TO REPORT ALL FEES PAID FOR COMPRESSING, GATHERING OR PROCESSING OF GAS AND GAS PRODUCTS, WITHOUT EXCEPTION.

TIMING

A completed AC5-V2 form must be received by the Client Services Help Desk, by May 15 of the year following the production year to which the report relates.

CONSEQUENCES OF NON-COMPLIANCE

Effective January 1999 the penalty of $1000 per month or part of a month for failing to file a AC5-V2 Form by its due date is replaced with a new penalty of $100 per month or part of a month until the form is received. If the form is not submitted, no custom processing allowance will be given for the production year to which the form relates. Also, operating costs will be recaptured if the royalty client does not have ownership interest in the Facility Cost Centre, and there have been no reported custom processing fees on the AC5 form.

AMENDING A CUSTOM PROCESSING FEES PAID REPORT

An amended AC5-V2 form must be completed in full same as with an initial AC5-V2 form.

AC5-V2 FORM - ALLOWABLE COSTS - CUSTOM PROCESSING FEES PAIDPART 1: IDENTIFICATION

1.1 **CLIENT ID** - The four-character EUB operator code or seven-character royalty client ID number assigned by the Department to the royalty client.

1.2 **CLIENT NAME** - The full name of the royalty client.

1.3 **PRODUCTION YEAR** - The production year to which the reported information applies

1.4 **DATE PREPARED** - The numeric year, month and day on which the AC5-V2 form is prepared.

1.5 **CONTACT PERSON** - The name of the person the Department can contact concerning information on the form.

1.6 **TELEPHONE** - The telephone number, including area code of the contact person.

PART 2: NON OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

NOTE: USE THIS SECTION OF THE FORM TO REPORT ELIGIBLE CUSTOM PROCESSING FEES PAID WHERE THE ROYALTY CLIENT HAS NO OWNERSHIP INTEREST IN ANY OF THE FACILITY COST CENTRES INVOLVED (I.E., COMPRESSING, GATHERING OR PROCESSING).

2.1 **CUSTOM PROCESSING FEE PAID** - The actual amount of the custom processing fee paid for services at the facility identified in *field 2.2.* The amount must be to the nearest dollar.

2.2 **EUB FACILITY PROV** - The province in which the facility is located; Alberta (AB), British Columbia (BC) or Saskatchewan (SK) **FAC. TYPE** - The type of facility; gas plant (GP) or gathering system (GS). **CODE** - The unique code assigned by the EUB which identifies the facility.

OFFICIAL DECLARATION

2.3 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer for the royalty client for whom the official declaration is made.

2.4 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 2.3.*

2.5 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 2.3.*

2.6 **DATE** - The date on which the authorized signing officer signed the official declaration.

NOTE: IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF FIELD 2.1.

PART 3: OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

NOTE: (1) Use this section of the form to report eligible custom processing fees paid where the royalty client may be an owner in some of the facility cost centres involved, and is custom processing through others. For example, a royalty client may have an ownership interest in a gathering system and is a custom user at a compressing and processing facility. The fee paid may relate to one or more of the compressing, gathering or processing services covered by the UOCR for the facility. A description of the eligible custom processing fees for compressing, gathering and processing facilities is provided in *Section 16.16*.

(2) If a royalty client has ownership interest in some **functional units** (Facility Cost Centres) of an EUB facility and is a custom user at similar functional units of the same EUB facility, the royalty client may submit a written request to the department requesting the monthly operating costs in lieu of receiving custom processing for the EUB facility. The written request must include supporting documentation that provides evidence that they are disadvantaged due to operating cost recaptures exceeding the custom processing fees paid in the production year. Once approved, in the subsequent production years, the Crown will continue to recognize an operating cost deduction in lieu of custom processing for the facility. No further custom processing fees will be recognized at the facility by the Crown. However, royalty clients must continue to submit an AC5 form providing custom processing fees and volumes for that facility to the department on an annual basis.

(3) If a royalty client has ownership interest in a Facility Cost Centre and is also paying custom processing fees for processing excess volumes at the same Facility Cost Centre, then:

- the royalty client will report in Field 3.2 the full custom processing fees. In Field 3.3, the total **excess capacity volumes** should be reported for the EUB facility. A checkmark *( )* should be placed in Field 3.4. This will enable a royalty client to claim the full **excess capacity fee** with no operating cost recapture. The reason UOCR will not be recaptured is that the excess capacity charge is intended to cover the capital and profit portion of custom processing and therefore has no operating expense component from which UOCR should be disallowed. In no case is a royalty client to receive duplicate UOCR recognition.

3.1 **EUB FACILITY** **PROV** - The province in which the facility is located; Alberta (AB), British Columbia (BC) or Saskatchewan (SK) **FAC. TYPE** - The type of facility; gas plant (GP) or gathering system (GS). **CODE** - The unique code assigned by the EUB which identifies the facility.

3.2 **CUSTOM PROCESSING FEE PAID** - The actual amount of the custom processing fee paid for services at the facility identified in *field 3.1*. The amount must be to the nearest dollar.

3.3 **ENERGY - ADJUSTED GAS EQUIVALENT VOLUME** - The volume of gas and gas products *(in energy- adjusted gas equivalent volumes)* obtained at the outlet of the facility for which the fee recorded in *field 3.2* was paid. To calculate the energy-adjusted gas equivalent volume for each custom processed facility outlet product, multiply the product volume in its base unit ($10^3m^3/m^3$/tonnes) by its energy-adjusted gas equivalent factor. The energy-adjusted gas equivalent factors are provided in Section 16.13.1. Sum up each product energy-adjusted gas equivalent volume to determine the total energy-adjusted gas equivalent volumes for the facility.

3.4 **EXCESS CAPACITY** - A checkmark *()* must be placed in this field if the reported fees and volumes are excess capacity.

3.5 **CUSTOM SERVICES PAID** - A checkmark *()* must be placed in the field or fields that describe the custom processing services for which the fee recorded in *field 3.2* were paid. For every volume listed in *field 3.3*, a corresponding checkmark must be placed in *field 3.5.* If it is left blank, the calculation will default to using the total unit operating cost (UOCR) at the EUB facility as operating cost recovery. For excess capacity volumes identified in *field 3.4, field 3.5* must still be completed.

NOTE: IF ADDITIONAL PAGES ARE USED, PLEASE STATE, "CONTINUATION PAGE(S) ARE ATTACHED", ON THE BOTTOM LINE OF FIELD 3.1.

OFFICIAL DECLARATION

3.6 **AUTHORIZED SIGNATURE** - The signature of the authorized signing officer of the royalty client for whom the official declaration is made. The form will be rejected if this is left blank.

3.7 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the authorized signing officer whose signature appears in *field 3.6.*

3.8 **TITLE OF CORPORATE SIGNING OFFICER** - The position title of the authorized signing officer whose signature appears in *field 3.6.*

3.9 **DATE** - The date on which the authorized signing officer signed the official declaration.

24.6 Preparing An Otherwise Flared Solution Gas Application Form

OFSG FORM – OTHERWISE FLARED SOLUTION GAS ROYALTY WAIVER PROGRAM

THIS FORM MUST BE COMPLETED BY BATTERY OPERATOR

PURPOSE

Royalty clients who have not pre-qualified for this program must complete the OFSG Application Form to apply for a royalty waiver on uneconomic solution gas that is used in a manner that requires the payment of Crown royalty.

The wells must be associated with a crude oil battery. Bitumen batteries are excluded from this royalty waiver program.

TIMING

Completed OFSG application forms will be date stamped by the Department of Resource Development on the day it is received. The application form will be forwarded in its entirety to the EUB for economic assessment. Approved forms will have the effective date status granted the first day of the month in which the form was received.

**For definition, please see Appendix N - Glossary*

OFSG FORM - COMPLETION INSTRUCTIONS

PART 1: CLIENT INFORMATION

1.1 **BATTERY OPERATOR ID** - The four-character EUB operator code for the battery ID listed in *field 3.1*.

1.2 **BATTERY OPERATOR NAME** - The full name of the royalty client whose code appears in *field 1.1*.

1.3 **DATE PREPARED** - The numeric year, month and day on which the OFSG form is prepared.

1.4 **CONTACT PERSON** - The name of the person whom the Department can contact concerning the information on the form.

1.5 **TELEPHONE** - The telephone number, including area code, of the contact person.

PART 2: APPLICATION DETAIL

Please attach to this form the necessary documentation as requried below:

- An application for royalty waiver requires an economic evaluation using the parameters outlined in Section 2.4 of the EUB Upstream Petroleum Industry Flaring Guide, G-60.
- The economic evaluation must include the optimal solution gas conservation case, which is defined as the conservation rate with the maximum Net Present Value (NPV).
- If the NPV of the optimal case is negative, 100% of the solution gas and byproducts will qualify for the royalty waiver.

PART 3: WELL IDENTIFIERS

3.1 **BATTERY ID** - The 7-digit battery ID for which the application relates.

3.2 **FIELD CODE** – The four-digit field code associated with the batter ID in *field 3.1*

3.3 **UNIQUE WELL IDENTIFIER** – The well(s) associated with the Battery ID as listed in *field 3.1*.

PART 4: CERTIFICATION

4.1 **SIGNATURE**- Signature of corporate signing officer representing the company identified in *field 1.1*

4.2 **DATE** - The date in which *field 4.1* was signed.

4.3 **NAME OF CORPORATE SIGNING OFFICER** - The full name of the individual whose signature appears in *field 4.1*.

4.4 **TITLE OF CORPORATE SIGNING OFFICER** - The official title of the individual whose signature appears in *field 4.1*

25. Levying and Collecting Natural Gas Royalty

25.1 Levy and Collection - Overview

The Department will establish a *Gas Account* for each royalty client. Charges will be recorded in the client's Gas Account for the following revenues:

- **Royalty Revenue** is the *net royalty amount due* as described on the monthly *Invoice.*
- **Royalty Deposit Revenue** is the royalty client's royalty deposit and any adjustments to the deposit as described on the monthly *Invoice*.
- **Interest Revenue** is *the current and previous period interest charges* as described on the monthly *Invoice* and the *Statement of Account.*
- **Penalties Revenue** is *the monthly and annual penalty charges* levied against a royalty client as described on the monthly *Invoice.*
- **Fees Revenue** is the *fee that may be charged for services provided by the Department*, as described on the monthly *invoice.*

The Department will submit a *Statement of Account, an Invoice and Crown Royalty Detail statements* to each royalty client for each billing period in which there are gas royalty transactions or in which the royalty client has other than a "zero balance" in his Gas Account with the Department.

The Department will issue the *Invoice* and the *Crown Royalty Detail statements* to each royalty client on or before the last day of the second month following each production month.

The Department will issue separately the *Statement of Account* to each royalty client on or before the 15th day of the third month following each production month.

Royalty clients are liable for payment of the amount owed the Crown on each invoice received from the Department on or before the last day of the third month following the production month to which the invoice relates.

A description of the business rules relating to royalty client accounts, application of payments, interest payable/receivable and account collection is provided in *Section 9.*

NOTE: ROYALTY CLIENTS WHO WISH TO RECEIVE THE STATEMENT OF ACCOUNT, INVOICE AND CROWN ROYALTY DETAIL STATEMENTS ELECTRONICALLY SHOULD CONTACT THE HELP DESK, CLIENT SERVICES.

25.2 Preparing a Payment Remittance

METHOD OF PAYMENT

There are four methods for remitting Crown natural gas royalty payments:

- by cheque through the mail or by courier;
- by direct deposit, using a Rapidtrans deposit slip;
- by electronic funds transfer; *or*
- by automatic debit.

A payment remittance that is *less than $5,000* may be made using *any one of the three methods*. A payment remittance that is ***$5,000 or more must*** be made by ***either direct deposit or electronic funds transfer***.

All remittances must be made payable to the *Provincial Treasurer, Alberta*. Remittances by direct deposit must be made using a Rapidtrans deposit slip *(a sample of the Rapidtrans deposit slip and the bank locations at which they may be used is provided in Appendix K)*. Remittances made by electronic funds transfer must be directed to the account of the *Provincial Treasurer, Account 09-35603*, at the Canadian Imperial Bank of Commerce.

Rapidtrans deposit slips may be obtained from the Department by contacting the Gas Royalty Branch or the Calgary Information Centre at the address or telephone number listed in *Appendix L*.

INFORMATION REQUIRED

The following information is required in remitting payment:

- payment date;
- name of the payer;
- name of each royalty client on whose behalf the payment is made;
- the four-character EUB operator code or seven-character royalty client ID assigned by the Department to that royalty client;
- *account number* assigned by the Department to that royalty client;
- account code to which the payment is to be credited, either "Gas" for pre-1994 royalty or "G94" for post-1993 royalty *(refer to Appendix J, for a list of applicable revenue accounts and associated codes)*;
- dollar amount of the payment or payments *(if remittance is made on behalf of the royalty client for more than one revenue account, each account/payment must be listed separately)*; *and*
- total amount of payment.

If payment is made by direct deposit, the required information *must* be entered directly onto the Rapidtrans deposit slip. If payment is made by mail or electronic funds transfer, the information *must* be provided to the Department by letter.

NOTE: A PAYMENT MAY INCLUDE AMOUNTS FOR CROWN NATURAL GAS ROYALTY AND ANY OF THE ACCOUNTS LISTED IN *APPENDIX J*.

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NOTE: The numbering of the items on this document is only for cross-referencing to the "Description of Entries" in the Guidelines. They do not form part of the "Statement of Account" document.

STATEMENT OF ACCOUNT

PART 1: ROYALTY PAYER INFORMATION
1.1 CODE
1.2 NAME
1.3 ADDRESS
PROV. POSTAL CODE

PART 2: REGULATORY AGENCY INFORMATION
2.1 ISSUER
2.2 ISSUE DATE YR. MO. DY.
2.3 STATEMENT NUMBER
2.4 ACCOUNT NUMBER

PART 3: ROYALTY DEPOSIT ACCOUNT

3.1 OPENING	3.2 ADJUSTMENT	3.3 CLOSING
$	$	$

PART 4: ACCOUNT SUMMARY

PART 5 ACCOUNTS

		5.1 PENALTY	5.1 INTEREST	5.1 ROYALTY	TOTAL	5.2 BALANCE DUE
4.1	PRODUCTION YEAR - 1994					
4.2	OPENING BALANCE	$	$	$	$	
4.3	PAYMENT APPLIED: YY/MM/DD	$	$	$	$	
4.4	CURRENT PERIOD CREDITS: INVOICE #XXXXXX	$	$	$	$	
4.5	CURRENT PERIOD CHARGES: INVOICE#XXXXXX	$	$	$	$	
4.6	ACCOUNT TRANSFERS:	$	$	$	$	
4.7	CLOSING BALANCE	$	$	$	$	$
	PRODUCTION YEAR - 1995					
	OPENING BALANCE	$	$	$	$	
	PAYMENT APPLIED: YY/MM/DD	$	$	$	$	
	CURRENT PERIOD CREDITS: INVOICE #XXXXXX	$	$	$	$	
	CURRENT PERIOD CHARGES: INVOICE#XXXXXX	$	$	$	$	
	ACCOUNT TRANSFERS: COMMENTS	$	$	$	$	
4.8	STATEMENT INTEREST CHARGES		$		$	
	CLOSING BALANCE	$	$	$	$	$
5.	ACCOUNT BALANCE					$

PART 6: STATEMENT INTEREST RATE = 0.00%
PART 7: COLLECTION NOTICE
PART 8: OUR REFERENCE NUMBER:

25.3 Gas Royalty Statement of Account

STATEMENT OF ACCOUNT

PURPOSE

The *Statement of Account* is the Department's monthly accounting to a royalty client for all transactions charged or credited to that client's *Gas Account.*

TIMING

The Department issues a Statement of Account to each active royalty client by the 15th day of the third month.

DESCRIPTION OF ENTRIES

The Statement of Account records transactions and balances by production year. Transactions will consist of the charges for penalties, interest and royalty, as summarized on the Invoice. The statement will report payments received and account transfers. Interest charges in respect of unpaid amounts will be calculated and reported separately on the Statement of Account under the current production year's interest column.

The Statement of Account will separately disclose balances and adjustments to the client's Royalty Deposit Account.

PART 1: ROYALTY PAYER INFORMATION - The royalty payer is the person responsible for discharging the royalty obligation of the royalty client; hence, the royalty payer can also be a royalty client.

1.1 **CODE** – The four-character EUB operator code or seven-character royalty payer ID number assigned by the Department. This code must be quoted when making payments.

1.2 **NAME** – The legal name of the royalty payer to whom the code is assigned.

1.3 **ADDRESS** – The mailing address of the royalty payer where the statement is sent.

PART 2: REGULATORY AGENCY INFORMATION

2.1 **ISSUER** – The regulatory agency issuing the statement, which is the Department.

2.2 **ISSUE DATE** – The date the statement was issued.

2.3 **STATEMENT NUMBER** – The unique number assigned by the Department. The number should be quoted when making enquiries about a statement.

2.4 **ACCOUNT NUMBER** – A unique number assigned to the royalty payer by the Department. The royalty payer must quote this number when making remittances.

PART 3: ROYALTY DEPOSIT ACCOUNT

3.1 **OPENING** – The royalty client's current opening *Royalty Deposit Balance*.

3.2 **ADJUSTMENT** – The result of a change to the royalty client's business. The amount represents an adjustment to the royalty deposit. The amount is indicated on the invoice and is included in the *Royalty* figure on the *Statement of Account*.

3.3 **CLOSING** – This is the deposit recorded by the Department at the issue date of the statement. It is the sum of the opening balance and the adjustment amount.

PART 4: ACCOUNT SUMMARY

NOTE: THE *STATEMENT OF ACCOUNT* SHOWS TRANSACTIONS AND BALANCES BY PRODUCTION YEAR.

4.1 **PRODUCTION YEAR** – The relevant production year will be shown if there is an outstanding balance or if there are current transactions to report.

4.2 **OPENING BALANCE** – The closing balance brought forward from the previous month's statement for the respective production year.

4.3 **PAYMENT APPLIED** – Payments received by the Department since the last statement. The date the payment was received is indicated here. The payment is allocated to the account items (namely penalty, interest and royalty) in accordance with *Section 26* of the *Natural Gas Royalty Regulation, 1994*. (*Refer to Section 9.6.*)

4.4 **CURRENT PERIOD CREDITS** - This represents the sum of the credits reported on the invoice. The invoice number, which reflects the total credits, is indicated here. The credit will be applied in the same way as a payment.

4.5 **CURRENT PERIOD CHARGES** - The sum of the charges reported on the invoice. The invoice number that reflects the total charges is indicated here.

4.6 **ACCOUNT TRANSFERS** – The amounts shown here represents transfers, in or out, requested by the royalty payer, and authorized by the Department. The nature of the transfer is indicated here.

4.7 **CLOSING BALANCE** – The closing balance by account and in total for the respective production year.

4.8 **STATEMENT INTEREST CHARGES** – The interest due to the Crown. Interest is calculated up to the issue date of the statement on the total overdue account balance since the last statement. The interest charge will be shown only on the current production year's interest column.

PART 5: ACCOUNTS

5.1 **REVENUE ACCOUNTS** – The charges and credits will be reflected under the appropriate revenue account, namely penalty, interest and royalty.

5.2 **BALANCE DUE** – Net amount due to the Crown or to the royalty payer for each of the production years.

5.3 **ACCOUNT BALANCE** – The royalty payer's total account balance. Any balance owing to the royalty

PART 6: **STATEMENT INTEREST RATE** - The current rate used by the Department to calculate interest on overdue balances.

PART 7: **COLLECTION NOTICE** - The field used to notify the clients of overdue accounts and the action that will be taken.

PART 8: **OUR REFERENCE NUMBER** - This uniquely identifies each document sent to a client. It distinguishes the original documents from duplicates that show different numbers.

25.3.1 Redesigned Gas Royalty Statement of Account

The Department has enhanced the gas royalty Statement of Account. This statement is effective with the March 1998 issue of the gas royalty Statement of Account.

The following explains the redesigned structure of the Statement of Account:

STATEMENT OF ACCOUNT

Transactions in the ***Account Summary*** portion of the Statement of Account are no longer split between production years and revenue types (i.e. Penalty, Interest, and Royalty). Instead, there is an ***Account Opening Balance***, which corresponds to the ***Account Closing Balance*** on the previous month's statement. Statement transactions appear in ascending order of transaction date that have been posted to the account (e.g. Payment, account transfers, posted current period interest, etc.). An Account Closing Balance appears after the last statement transaction. If the closing balance includes prior period charges, the current period interest accrued to the ***Statement Issue Date*** is shown. These charges are already past due and continues to accrue interest until payment is received. Supporting details indicating the principal amount, interest effective dates, interest rate, as well as a per diem amount, will be provided to allow clients to effectively calculate the amount payable as of a given date. (Please note that accrued interest does not form part of the Account Closing Balance). An ***Amount Payable*** as of the Statement Issue Date is indicated on the new statement. This amount includes the Account Closing Balance and the current period interest that has accrued up to the Statement Issue Date on charges that are past due. If payments are made after this date, the client must factor in the additional interest that has accrued since that date.

Transaction dates and IDs. are given on the statements to facilitate referencing. A transaction date is the date on which the statement transaction is considered to have occurred for the purpose calculating current period interest. ***Current Invoice Charges*** on the statement show the invoice number rather than the transaction ID.

With the statement transactions, when a payment is received (either from a direct payment or a transfer of funds from other accounts), any current period interest owing on the account balance is posted to the account as of the payment date. Supporting details indicating the principal amount, interest effective dates and interest rate are now provided.

Current Invoice Charges on the new statement distinguishes ***Prior Period Charges*** from ***Current Period Charges***. The ***Current Period Interest*** (CPI) commencement date will be included with each charge. CPI will commence the first day after the Invoice Issue Date for Prior Period Charges and the first day after the ***Invoice Due Date*** for Current Period Charges.

An example of the new Statement of Account is given on next page.

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Example 1: Depicting Level 1 Collection Notice
Assuming all of the opening balance relates to charges which were due on 1997/10/31.

STATEMENT OF ACCOUNT

ROYALTY PAYER INFORMATION	
CODE:	1234
NAME:	PARENT COMPANY
ADDRESS:	XXXXXXXXXXXXXXXXXXX CALGARY, AB CANADA X9X 9X9

REGULATORY AGENCY INFORMATION	
ISSUER:	DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE:	1997-11-10
STATEMENT NUMBER:	
ACCOUNT NUMBER:	G94XXXXXX

ROYALTY DEPOSIT ACCOUNT		
OPENING $	ADJUSTMENT $	CLOSING $
500,000.00	0.00	500,000.00

ACCOUNT SUMMARY		TOTAL $
OPENING BALANCE		250,000.00
PAYMENT APPLIED: 1997/10/29 TXN ID XXXXXXXX		(150,000.00)
CURRENT INVOICE CHARGES: 12345678901		346,449.00
PRIOR PERIOD CHARGES $: CPI COMMENCING 1997/11/01	62,949.00	
CURRENT PERIOD CHARGES $: CPI COMMENCING 1997/12/01	283,500.00	
PAYMENT APPLIED: 1997/11/07 TXN ID XXXXXXXX		(100,000.00)
CURRENT PERIOD INTEREST POSTED: 1997/11/07 TXN ID XXXXXXXX		179.69

PRINCIPAL $	FROM	TO	INTEREST RATE	INTEREST AMOUNT $
162,949.00	1997/112/01	1997/11/07	5.750%	179.69

CLOSING BLANCE $346,628.69

CURRENT PERIOD INTEREST ACCRUED BUT UNPOSTED: TO 1997/11/10 29.75

PRINCIPAL $	FROM	TO	INTEREST RATE	INTEREST AMOUNT $	PER DIEM AMOUNT $
62,949.00	1997/11/08	1997/11/10	5.750%	29.75	9.92

AMOUNT PAYABLE: AS OF 1997/11/10 $346,658.44

COLLECTION NOTICE: PLEASE NOTE YOUR CLOSING BALANCE INCLUDES CHARGES PAST DUE WHICH ARE ACCRUING ADDITIONAL INTEREST UNTIL PAYMENT IS RECEIVED

MESSAGE(S): RE: ALBERTA ROYALTY TAX CREDIT: SEE THE ARTICLE IN OUR JULY '97 INFORMATION BULLETIN ABOUT NEW REPORTING REQUIREMENTS FROM ALBERTA TREASURY WITH RESPECT TO THE ALBERTA TAX CREDIT AND ROYALTY CREDIT FOR INDIVIDUALS AND TRUSTS PROGRAMS, RELATED TO GAS ROYALTY ADJUSTMENTS FOR 1994 TO 1996.

CC: ALBERTA TREASURY, TAX AND REVENUE ADMINISTRATION

Reference Number: 12345678

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NOTE: The numbering of the items on this document is only for cross-referencing to the "Description of Entries" in the Guidelines. They do not form part of the "Invoice" document.

INVOICE

PART 1: ROYALTY PAYER INFORMATION

1.1 CODE ☐
1.2 NAME ☐
1.3 ADDRESS ☐
☐
☐☐☐☐☐☐☐☐ PROV POSTAL CODE

PART 2: REGULATORY AGENCY

2.1 ISSUER ☐
2.2 ISSUE DATE ☐☐☐☐☐☐☐☐ YR MO.
2.3 DUE DATE ☐☐☐☐☐☐☐☐ YR MO.
2.4 BILLING ☐☐☐☐☐☐ YR MO.
2.5 INVOICE NUMBER ☐
2.6 ACCOUNT NUMBER ☐

PART 3:

3.1	CROWN ROYALTY	$
3.2	MONTHLY PROPRIETARY WAIVER	$
3.3	MONTHLY CAPITAL COST DEDUCTION	$
3.4	MONTHLY CUSTOM PROCESSING FEE DEDUCTION	$
3.5	ANNUAL CO-GENERATION CONTRACT ADJUSTMENT	$
3.6	ANNUAL CAPITAL COST ADJUSTMENT	$
3.7	ANNUAL CUSTOM PROCESSING FEE ADJUSTMENT	$
3.8	ALLOWABLE COST RESTRICTION	$
3.9	ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT	$
3.10	INJECTION CREDITS	$
3.11	ENHANCED OIL RECOVERY OPERATING COST ADJUSTMENT	$
3.12	CROWN ROYALTY PAID BANK SETTLEMENT	$
3.13	CROWN ROYALTY INVENTORY SETTLEMENT	$
3.14	AUDIT ADJUSTMENTS	$
3.15	COMPENSATORY ROYALTY	$
3.16	TRESPASS DAMAGES	$
3.17	SULPHUR EMISSION CONTROL ASSISTANCE PROGRAM (SECAP)	$
3.18	ROYALTY DEPOSIT ADJUSTMENT	$
3.19	OTHER FINANCIAL TRANSACTIONS	$
3.20	PROVISIONAL ROYALTY ASSESSMENT	$
3.21	FEE	$
3.22	PENALTIES	$
3.23	INTEREST: PRIOR PERIOD	$
3.24	CURRENT PERIOD TOTAL	$

3.25 TERMS AND CONDITIONS:

3.26 CHEQUES PAYABLE TO:

88/01/3

3.27 OUR REFERENCE NUMBER: ☐

25.4 Gas Royalty Invoice

INVOICE

PURPOSE

An *Invoice* is generated by the Department monthly and sent to a royalty client for all royalty transactions charged and credited to that royalty client during the Billing Period (*Refer to Section 9*).

TIMING

The Department issues an Invoice to each royalty client who has Crown natural gas royalty transactions in a Billing Period, on or before the last day of the second month following the *production month* to which the Invoice relates.

DESCRIPTION OF ENTRIES

NOTE: THE AMOUNTS ON THE INVOICE ARE REPORTED AS POSITIVE NUMBERS. THE EFFECT OF EACH LINE ITEM IS UNDERSTOOD AS TO WHETHER IT GENERALLY INCREASES OR DECREASES THE OVERALL LIABILITY TO THE CROWN. THEREFORE, IF A NEGATIVE SIGN IS DISPLAYED BEFORE ANY AMOUNT, THE EFFECT WILL BE TO EITHER ADD OR DEDUCT THAT AMOUNT FROM THE OVERALL LIABILITY TO THE CROWN DEPENDING ON WHETHER THAT LINE ITEM GENERALLY INCREASES OR DECREASES THE LIABILITY TO THE CROWN. FOR EXAMPLE, CAPITAL COST ALLOWANCE IS GENERALLY A DEDUCTION FROM THE CROWN ROYALTY; THEREFORE, AN ANNUAL CAPITAL COST ADJUSTMENT WILL ALSO BE A DEDUCTION FROM CROWN ROYALTY IF A NEGATIVE SIGN IS NOT DISPLAYED BESIDE THAT AMOUNT. HOWEVER, IF A NEGATIVE SIGN IS INDICATED BESIDE THE ANNUAL CAPITAL COST ADJUSTMENT, THE AMOUNT WILL BE ADDED TO THE OVERALL LIABILITY TO THE CROWN.

The following is a description of the charges and credits that will be reported on the Invoice.

PART 1: **ROYALTY PAYER INFORMATION** - Royalty payer is the person responsible for discharging the royalty obligations of the royalty client; hence, the royalty payer can also be a royalty client.

1.1 **CODE** - The four-character EUB operator code or seven-character royalty payer ID number assigned by the Department.

1.2 **NAME** - The legal name of the royalty payer to whom the code is assigned to.

1.3 **ADDRESS** - The mailing address of the person where the invoice is sent.

PART 2: REGULATORY AGENCY INFORMATION

2.1 **ISSUER** - The regulatory agency issuing the invoice, which is the Department.

2.2 **ISSUE DATE** - The date the invoice was issued. All prior-period interest is calculated up to this date.

2.3 **DUE DATE** - The date on or before which the Department must receive payment of the invoiced amount.

2.4 **BILLING PERIOD** - The production year and month for which an invoice is issued. One billing period may include amendments for prior-production periods.

2.5 **INVOICE NUMBER** – The unique number assigned by the Department to distinguish a particular company's invoice. This number should be quoted when making enquiries about an invoice.

2.6 **ACCOUNT NUMBER** – This is a unique number assigned to the royalty payer by the Department. The royalty payer must quote this number when making remittances.

PART 3: CROWN ROYALTY AND OTHER MONTHLY/ANNUAL ITEMS

3.1 **CROWN ROYALTY** – The sum of all Crown royalty "charge type" brought forward from the Crown Royalty Detail Calculation Statement for the same billing period. This amount may be negative if a royalty client overpaid Crown royalties in the previous period.

3.2 **MONTHLY PROPRIETARY WAIVER** – The amount deducted on account of proprietary waivers (PW1 form) processed during the billing period. The amount may be negative if a royalty client over claimed the deduction in the previous period. A negative amount will be added to the Crown royalty. (*Refer to Section 5.2.3. and Section 20.3*)

3.3 **MONTHLY CAPITAL COST DEDUCTION** – The amount deducted for estimated monthly Allowable Capital Cost. (*Refer to Section 16.1.1.*)

3.4 **MONTHLY CUSTOM PROCESSING FEES DEDUCTION** – The amount deducted for estimated monthly Allowable Custom Processing Fees paid by the royalty client. (*Refer to Section 16.1.1.)*

3.5 **ANNUAL CO-GENERATION CONTRACT ADJUSTMENT** – Applies only to royalty clients whose Crown royalty share of gas is valued using the *Gas Reference Price,* and who have *grandfathered co-generation or similar long-term contracts.* It is the amount of any adjustment required on the difference between the monthly valuation of grandfathered contracts at reference price and the annual calculation using the actual contract prices. If the amount is indicated as negative, it will be added to the Crown royalty to reflect underpayment of Crown royalty in the previous period. *(Refer to Section 6.4.1 The adjustment will be invoiced in June following the production year.)*

3.6 **ANNUAL CAPITAL COST ADJUSTMENT** – The adjustment required on the difference between estimated Allowable Capital Cost deducted during the year and actual Allowable Capital Cost calculated for that year. A positive adjustment amount will be deducted from the Crown royalty and a negative adjustment amount will be added to the Crown royalty. *(Refer to Section 16.2.1. The adjustment will be invoiced in June following the production year.)*

3.7 **ANNUAL CUSTOM PROCESSING FEE ADJUSTMENT** – The adjustment required because of the difference between estimated Allowable Custom Processing Fee deducted during a year and actual Allowable Custom Processing Fee calculated for that year. A positive adjustment amount will be deducted from the Crown royalty and a negative adjustment amount will be added to the Crown royalty. *(Refer to Section 16.2.1. The adjustment will be invoiced in June following the production year.)*3.8

ALLOWABLE COST RESTRICTION (MONTHLY) – Represents a recovery of allowable costs that turned the Crown royalty into a negative amount. Royalty clients cannot claim costs in excess of Crown royalty payable. *(Refer to Section 7.2.)*

3.9 **ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT** – Represents an annual adjustment (recovery) of costs claimed in excess of the total royalty due to the Crown, after incorporating all annual adjustment items.

3.10 **INJECTION CREDITS** – The sum of all Injection Credit "charge type" brought forward from the Crown Royalty Detail Calculation statements for the same billing period. It represents a credit to the royalty clients in respect of gas and gas products delivered to the injection facility for the purpose of injecting. The value of injection credits are not affected by operating costs. This amount may be negative if a royalty client over claimed injection credits in the previous period. A negative amount will be added to the Crown royalty. *(Refer to Section 5.3.1.and Section 20.4)*

3.11 **ENHANCED OIL RECOVERY OPERATING COST ADJUSTMENTS** – The sum of all EOR Operating Cost Adjustment "charge type" brought forward from Crown royalty detail calculation statements for the same billing period. It represents a recovery of operating cost based on the lesser of proprietary volumes *produced from* versus *injected into* approved EOR schemes. A positive amount will be added to the Crown royalty and a negative amount will be deducted from the Crown royalty. *(Refer to Section 20.5)*

3.12 **CROWN ROYALTY PAID BANK SETTLEMENT** – This is the sum of all Crown Royalty Paid Bank Settlement "charge type" brought forward from the Crown royalty detail calculation statements for the same billing period. It represents a credit to a royalty client because of the payout of Crown royalty paid banks existing on January 1, 1994. If the amount is indicated as negative, it will be added to the Crown royalty to reflect overpayment by the Crown in the previous period. *(Refer to Section 18.2.)*

3.13 **CROWN ROYALTY INVENTORY SETTLEMENT** – This is the sum of all Crown Royalty Inventory Settlement "charge type" brought forward from the Crown royalty detail calculation statements for the same billing period. It represents a charge to a royalty client because of Crown royalty inventory existing on January 1, 1994. If the amount is indicated as negative, it will be deducted from the Crown royalty to reflect overpayment to the Crown in the previous period. *(Refer to Section 18.3.)*

3.14 **AUDIT ADJUSTMENTS** – A charge or a credit to a royalty client because of an audit, where the results are not processed through amended reporting. A positive amount will be added to the Crown royalty and a negative amount will be deducted from the Crown royalty.

3.15 **COMPENSATORY ROYALTY** – A charge to a royalty client because of Compensatory Royalty. This amount may be negative if a royalty client was over-billed for Compensatory Royalty in the previous period. A negative amount will be deducted from Crown royalty. *(Refer to Section 17.2. The calculation is provided to support the charge.)*

3.16 **TRESPASS DAMAGES** – A charge to a royalty client because of Trespass Damages. This amount may be negative if a royalty client was over-billed for Trespass Damages in the previous period. A negative amount will be deducted from Crown royalty. *(Refer to Section 17.3. The calculation is provided to support the charge.)*

3.17 3.17 **SULPHUR EMISSION CONTROL ASSISTANCE PROGRAM (SECAP)** – A credit to a royalty client because of SECAP. A positive amount will be deducted from the Crown royalty and a negative amount will be added to the Crown royalty. *(Refer to Section 8.4 and Section 17.4. The calculation is provided to support the credit.)*

3.18 **ROYALTY DEPOSIT ADJUSTMENT** – A deposit amount for a new royalty client, or an adjustment to the deposit for an existing client. A negative amount represents an overpayment of past deposits and will be deducted from the Crown royalty. *(The deposits for all the clients are adjusted annually and are invoiced in the May billing period following the production year. Refer to Section 9.4.)*

3.19 **OTHER FINANCIAL TRANSACTIONS** – A net charge or a credit of a miscellaneous nature. As this is derived manually, supporting documents will be sent to the royalty client. A positive amount will be added to the Crown royalty and a negative amount will be deducted from the Crown royalty.

3.20 **PROVISIONAL ROYALTY ASSESSMENT** – The sum of all Provisional Royalty Assessment "charge type" brought forward from the Crown Royalty Detail Calculation statements. It represents a charge to a royalty client because of reconciliation differences. A negative amount represents a reversal of the charge and will be deducted from the Crown royalty. *(Refer to Section 10.2.)*

3.21 **FEES** – *This may be implemented at a later date.*

3.22 **PENALTIES** – The charge to a royalty client because of late submission of the required forms. A negative amount represents a reversal of a penalty charge and will be deducted from the Crown royalty. *(Refer to Section 10.3. An analysis is provided to support the penalty charge and the type of form to which it relates. Penalty charges may span several production years.)*

3.23 **INTEREST: PRIOR PERIOD** – A sum of all charges and credits brought forward from the Crown royalty detail statements for the same billing period. It represents net interest charged or credited to a royalty client as a result of amendments received for prior period reporting. A positive amount will be added to the Crown royalty and a negative amount will be deducted from the Crown royalty.

3.24 **CURRENT PERIOD TOTAL** – The total amount due to or payable by the Crown for the current billing period. A negative amount represents overpayment to the Crown and will be refunded to the royalty client. *(Refer to Section 9.5)*

3.25 **TERMS AND CONDITIONS** – The terms and conditions of payment of the invoice.

3.26 **CHEQUES PAYABLE TO** - Information to the royalty payers as to whom the cheques should be made payable.

3.27 **DEPARTMENTAL REFERENCE NUMBER** - This identifies each document sent to the royalty clients as being unique. It distinguishes the original documents from duplicates which have different numbers.

25.4.1 Redesigned Gas Royalty Invoice

The Department has enhanced the gas royalty Invoice. This Invoice will be effective with the 1998-01 Billing Period's Invoice that is issued in March 1998. The following explains the redesigned structure of the Invoice and the related reports:

INVOICE, BILLING PERIOD AND PRODUCTION YEAR DETAIL REPORTS, AND CROWN ROYALTY DETAIL SUMMARY REPORT

(Examples of the new Invoice, Billing Period and Production Year Reports and Crown Royalty Detail Summary Report are given on pages 25-16 to 25-22).

INVOICE

The invoice has two additional columns to differentiate ***Prior Period Charges*** from ***Current Period Charges*** associated with each charge item on the Invoice. The new columns on the Invoice are intended to distinguish different due dates of these charges. Prior Period Charges are due as of the Invoice issue date. Current Period Charges are due as of the Invoice due date. Current period interest starts to accrue on the first day after the due date of the charge until the payment is received. The Invoice User Defined File (UDF) has also been revised to incorporate this change.

All charge types on the **Invoice, Billing Period Detail** and **Production Year Detail** are placed into one of three categories: Charges, Credits, or Adjustments:

- Charges include those charge types that increase royalty payable. Net reversals of these charge types appear as negatives but will remain in the 'Charges' category.
- Credits include those charge types that decrease royalty payable. Net reversals of these charge types appear as positives but will remain in the 'Credits' category.

- Adjustments include those charge types that can either increase or decrease royalty payable, and as such can appear as either positives or negatives.

BILLING PERIOD DETAIL

The Billing Period Detail report is separated into two reports, one identifying ***Prior Period Charges*** and the other identifying ***Current Period Charges*** that are calculated in the current billing period. In each report, the charges are listed by production period and charge type. Annual charge items are identified by the production year followed by the text "Annual". Annual production periods are shown after the monthly production periods. Charges on each Billing Period Report are now identified as ***Automated*** or ***Manual.*** Automated charges are calculated via the automated MRIS process. Manual charges are calculated via the manual MRIS process. ***Prior Period Charges*** on the Billing Period Report are further identified as to whether it is a ***Charge*** or an ***Interest*** item. Any prior period interest calculated for a charge item will appear in the Interest column of that charge while royalty charges will appear in the Charge column. The sum from the Interest column equates back to the Prior Period Interest charge item on the Invoice. The ***Current Period Charges*** on the Billing Period Report are not identified as Interest or Charge since there would be no prior period interest associated with current period charges. The totals on each of the Billing Period reports reconciles back to the total Prior Period and Current Period Charges on the Invoice. (Billing Period Report in UDF format is not available).

PRODUCTION YEAR DETAIL

The Production Year Detail report summarizes charge information by production period for all invoice charges calculated in each of the billing periods to date. Charges are no longer combined (eg. Sum of Other Charges) or summed at the annual level (eg. Monthly CC Deduction). Client may not have charges in every charge type, however, they are still listed on the report. Charge information from each ***Charge Type*** is summarized on the report by production and billing period. Annual charge items are identified by the production year followed by the text "Annual". Annual production periods are shown after the monthly production periods. Charges on the report are grouped by charge category like those on the Invoice (e.g. Charge, Credit, Adjustment). A total is calculated for each group and summed to obtain the ***Total Net Royalty.*** (Production Year Report in UDF format is not available.)

Production year totals are given for the following ***Monthly Charge Types***:

- Monthly Capital Cost Deduction
- Monthly Custom Processing Fee Deduction
- Allowable Cost Restriction

The Total Net Royalty is based on the sum of Charges Sub-Total, Credits Sub-Total and Adjustments Sub-Total.

For ***Annual Charge Types***, a breakdown by ***Billing Period*** is given. Charge types included are:

- Annual Capital Cost Adjustment
- Annual Custom Processing Fee Adjustment
- Annual Allowable Cost Restriction Adjustment
- Annual Co-Gen. Contract Adjustment
- (Annual) Royalty Deposit Adjustment

The charge types (i.e. Charges, Credits and Adjustments) that are shown in the **Invoice, Billing Period Detail and Production Year Detail** reports are described in the following table under the three headings:

CHARGES	CREDITS	ADJUSTMENTS
Crown Royalty	Monthly Proprietary Waiver	Annual Co-Generation Contract Adjustment
Allowable Cost Restriction	Monthly Capital Cost Deduction	Annual Capital Cost Adjustment
Enhanced Oil Recovery Operating Cost Adjustment	Monthly Custom Processing Fee Deduction	Annual Allowable Cost Restriction Adjustment
Crown Royalty Inventory Settlement	Injection Credits	Audit Adjustments
Provisional Royalty Assessment	Crown Royalty Paid Bank Settlement	Royalty Deposit Adjustment
Fees	SECAP	Other Financial Transactions
Penalties		Prior Period Interest

CROWN ROYALTY DETAIL SUMMARY REPORT

In order to reconcile the Crown Royalty Detail (CRD) Report to the Invoice and Billing Period Reports, a Crown Royalty Detail Summary report has been developed to supplement the existing Crown Royalty Detail Report. This summary report is generated for each royalty client and royalty payer and is only produced with a Crown Royalty Detail Report. Crown Royalty Detail Reports are produced for clients who have automated (system generated, not manually processed) charges for the following Charge Types:

(1) Crown Royalty
(2) EOR Operating Cost Adjustment
(3) Injection Credit
(4) Crown Royalty Paid Bank Settlement
(5) Crown Royalty Inventory Settlement and
(6) Provisional Royalty Assessment.

The Crown Royalty Detail Summary will group invoice charges by ***CRD*** and ***Non-CRD Charge Types***. CRD Charge Types are the same as (1) to (6) mentioned above. Non-CRD Charge Types are charge types that are not in the CRD group. Within each group, the charges will be identified as Prior Period Charges and Current Period Charges, similar to the Invoice. Prior Period and Current Period Charges are further separated into ***Automated*** and ***Manual*** Charges and identified as a Charge or an Interest item, similar to the Billing Period Reports. Any prior period interest calculated for a charge item will appear in the Interest column of that charge while its royalty charges will appear in the Charge column. The sum from the Interest columns equates back to the Prior Period Interest charge item on the Invoice. Note that Current Period Charges are not further identified as Interest or Charge since there would be no prior period interest associated with current period charges. The totals on the Crown Royalty Detail Summary reconcile back to the total charges on the Invoice and the Billing Period Reports. The Crown Royalty Detail User Defined File (UDF) has been revised to incorporate this change.

Alberta
RESOURCE DEVELOPMENT

INVOICE

ROYALTY PAYER INFORMATION

CODE:	1234
NAME:	PARENT COMPANY
ADDRESS:	XXXXXXXXXXXXXXXXXXX CALGARY, AB CANADA X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER:	DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE:	1997-10-31
INVOICE DUE DATE:	1997-11-30
BILLING PERIOD:	1997-08
INVOICE NUMBER:	12345678901
ACCOUNT NUMBER:	G94XXXXXX

		Prior Period $	Current Period $	Total $
Charges:				
	Crown Royalty	59,000.00	250,000.00	309,000.00
	Enhanced Oil Recovery Operating cost Adjustment	10,000.00	50,000.00	60,000.00
	Provisional Royalty Assessment	10,000.00	25,000.00	35,000.00
	Penalties		5,000.00	5,000.00
	Total Charges	79,000.00	330,000.00	409,000.00
Credits				
	Monthly Proprietary Waiver	(15,000.00)		(15,000.00)
	Monthly Capital Cost Deduction		(15,000.00)	(15,000.00)
	Monthly Custom Processing Fee Deduction		(5,000.00)	(5,000.00)
	Injection Credits		(25,000.00)	(25,000.00)
	Total Credits	(15,000.00)	(45,000.00)	(60,000.00)
Adjustments				
	Annual Capital Cost Adjustment	(5,000.00)		(5,000.00)
	Annual Custom Processing Fee Adjustment	(1,000.00)		(1,000.00)
	Other Financial Transactions		(1,500.00)	(1,500.00)
	Interest: Prior Period	4,949.00		4,949.00
	Total Adjustments	(1,051.00)	(1,500.00)	(2,551.00)
TOTAL:		$62,949.00	$283,500.00	$346,449.00

Terms and Conditions: The 'Prior Period Total' is now due and includes prior period interest to the invoice issue date and will continue to accrue current period interest commencing the first day after the invoice ISSUE date until payment is received. The 'Current Period Total' is due on the Invoice Due Date and will incur current period interest commencing the first day after the invoice DUE date.
The Department will charge interest on underpayments or late payments of invoiced amounts commencing the first day after the due date and continuing until the date the payment is received. Interest will be calculated at the Alberta Treasury Branch prime lending rate plus 1%. Interest will not be paid on overpayments of invoiced amounts.

RESOURCE DEVELOPMENT

1997/08 BILLING PERIOD DETAIL – PRIOR PERIOD CHARGES

ROYALTY PAYER INFORMATION

CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

Production	Charge	Automated		Manual		Total	
Period	Type	Charges $	Interest $	Charges $	Interest $	Charges $	Interest $
1994/01	Crown Royalty	1,000.00	10.00			1,000.00	10.00
	Provisional Royalty Assessment	10,000.00	100.00			10,000.00	100.00
1994/01 Sub-Total		11,000.00	110.00	0.00	0.00	11,000.00	110.00
1994/02	Crown Royalty	-2,000.00	-200.00			-2,000.00	-200.00
	Enhanced Oil Recovery Operating Cost Adjustment	10,000.00	99.00			10,000.00	99.00
1994/02 Sub-Total		8,000.00	-101.00	0.00	0.00	8,000.00	-101.00
1994 Annual	Annual Capital cost Adjustment	-5,000.00	-50.00			-5,000.00	-50.00
	Annual Custom Processing Fee Adjustment	-1,000.00	-10.00			-1,000.00	-10.00
1994 Annual Sub-Total		-6,000.00	-60.00	0.00	0.00	-6,000.00	-60.00
1997/07	Crown Royalty	50,000.00		10,000.00		60,000.00	
	Monthly Proprietary Waiver			-15,000.00		-15,000.00	
	Interest: Prior Period				5,000.00		5,000.00
1997/07 Sub-Total		50,000.00	0.00	-5,000.00	5,000.00	45,000.00	5,000.00
PRIOR PERIOD SUB-TOTAL		63,000.00	-51.00	-5,000.00	5,000.00	58,000.00	4,949.00

TOTAL PRIOR PERIOD CHARGE: $62,949.00

Reference Number 1234567

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Alberta
RESOURCE DEVELOPMENT

PRODUCTION YEAR DETAIL 1994

ROYALTY PAYER INFORMATION

CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

Production Period	Billing Period	Invoice Number	Crown Royalty $	EOR Operating Cost Adjustment $	Crown Royalty Inventory Settlement	Allowable Cost Restriction $	Provisional Royalty Assessment $	Penalties $	Charges Sub-Total $	Injection Credit $
1994/01	1994-01	12345678000	250,000.00	50,000.00			25,000.00	5,000.00	330,000.00	-25,000.00
	1997/08	12345678901	1,000.00				10,000		11,000.00	
1994/01 Sub-Total			251,000.00	50,000.00	0.00	0.00	35,000.00	5,000.00	341,000.00	-25,000.00
1994/02	1994/02	12345678532	250,000.00	50,000.00			25,000.00	5,000.00	330,000.00	-25,000.00
	1997/08	12345678901	-2,000.00	10,000.00					8,000.00	
1994/02 Sub-Total			248,000.00	60,000.00	0.00	0.00	25,000.00	5,000.00	338,000.00	-25,000.00
1994 Annual	1996/04	12345678804								
	1997/08	12345678901								
1994 Total			$499,000.00	$110,000.00	$0.00	$0.00	$60,000.00	$10,000.00	$679,000.00	-$50,000.00

Alberta
RESOURCE DEVELOPMENT

PRODUCTION YEAR DETAIL 1994

ROYALTY PAYER INFORMATION

CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

Production Period	Billing Period	Invoice Number	Crown Royalty Paid Bank Settlement $	Monthly Proprietary Waiver $	Monthly Capital Cost Deduction $	Monthly Custom Processing Fee Deduction $	SECAP $	Credits Sub-Total $	Annual Co-Gen Contract Adjustments $	Annual Capital Cost Ajustment $
1994/01	1994-01	12345678000			-15,000.00	-5,000.00		-45,000.00		
	1997/08	12345678901								
1994/01 Sub-Total			0.00	0.00	-15,000.00	-5,000.00	0.00	-45,000.00	0.00	0.00
1994/02	1994/02	12345678532			-15,000.00	-5,000.00		-45,000.00		
	1997/08	12345678901								
1994/02 Sub-Total			0.00	0.00	-15,000.00	-5,000.00	0.00	-45,000.00	0.00	0.00
1994 Annual	1996/04	12345678804							-2,200.00	-15,000.00
	1997/08	12345678901								-5,000.00
									-2,200.00	-20,000.00
1994 Total			$0.00	$0.00	-$30,000.00	-$10,000.00	$0.00	-$90,000.00	-$2,200.00	-$20,000.00

Reference Number: 1234567

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CROWN ROYALTY DETAIL SUMMARY

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

ROYALTY CLIENT SUMMARY:		Prior Period Charges $					Current Period Charges $		
		Automated		Manual			Automated	Manual	
		Charges $	Interest $	Charges $	Interest $	Total $	Charges $	Charges $	Total $
CRD CHARGE TYPE:	Crown Royalty	49,000.00	-190.00	10,000.00		58,810.00	250,000.00		250,000.00
	Enhanced Oil Recovery Operating Cost Adjustment	10,000.00	99.00			10,099.00	50,000.00		50,000.00
	Injection Credits						-25,000.00		-25,000.00
	Provisional Royalty Assessment	10,000.00	100.00			10,100.00	25,000.00		25,000.00
CRD TOTAL		69,000.00	9.00	10,000.00	0.00	79,009.00	300,000.00	0.00	300,000.00
NON CRD CHARGE TYPE	Annual Capital Cost Adjustment	-5,000.00	-50.00			-5,050.00			
	Annual Custom Processing Fee Adjustment	-1,000.00	-10.00			-1,010.00			
	Interest Prior Period				5,000.00	5,000.00			
	Monthly Capital Cost Deduction						-15,000.00		-15,000.00
	Monthly Crown Processing Fee Deduction						-5,000.00		-5,000.00
	Monthly Proprietary Waiver			-15,000.00		-15,000.00			
	Penalties						5,000.00		5,000.00
	Other Financial Transactions							-1,500.00	-1,500.00
NON CRD TOTAL		-6,000.00	-60.00	-15,000.00	5,000.00	-16,060.00	-15,000.00	-1,500.00	-16,500.00
		$63,000.00	-$51.00	-$5,000.00	$5,000.00	$62,949.00	$285,000.00	-$1,500.00	$283,500.00

ROYALTY PAYOR SUMMARY		Prior Period Charges $					Current Period Charges $		
		Automated		Manual			Automated	Manual	
		Charges $	Interest $	Charges $	Interest $	Total $	Charges $	Charges $	Total $
CRD CHARGE TYPE	Crown Royalty	49,000.00	-190.00	10,000.00		58,810.00	250,000.00		250,000.00
	Enhanced Oil Recovery Operating Cost Adjustment	10,000.00	99.00			10,099.00	50,000.00		50,000.00
	Injection Credits						-25,000.00		-25,000.00
	Provisional Royalty Assessment	10,000.00	100.00			10,100.00	25,000.00		25,000.00
CRD TOTAL		69,000.00	9.00	10,000.00	0.00	79,009.00	300,000.00	0.00	300,000.00
NON CRD CHARGE TYPE	Annual Capital Cost Adjustment	-5,000.00	-50.00			-5,050.00			
	Annual Custom Processing Fee Adjustment	-1,000.00	-10.00			-1,010.00			
	Interest Prior Period				5,000.00	5,000.00			
	Monthly Capital Cost Deduction						-15,000.00		-15,000.00
	Monthly Custom Processing Fee Deduction						-5,000.00		-5,000.00
	Monthly Proprietary Waiver			-15,000.00		-15,000.00			
	Penalties						5,000.00		5,000.00
	Other Financial Transactions							-1,500.00	-1,500.00
NON CRD TOTAL		-6,000.00	-60.00	-15,000.00	5,000.00	-16,060.00	-15,000.00	-1,500.00	-16,500.00
TOTAL		$63,000.00	-$51.00	-$5,000.00	$5,000.00	$62,949.00	$285,000.00	-$1,500.00	$283,500.00

Reference Number: 1234567

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RESOURCE DEVELOPMENT

PRODUCTION YEAR DETAIL 1994

ROYALTY PAYER INFORMATION

CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

Production Period	Billing Period	Invoice Number	Annual CP Fee Adjustment $	Annual ACR Adjustment $	Royalty Deposit Adjustment $	Audit Adjustment $	Other Financial Transactions $	Interest: Prior Period $	Adjustments Sub-Total $	Total Net Royalty $
1994/01	1994-01	12345678000					-1,500.00		-1,500.00	283,500.00
	1997/08	12345678901						110.00	110.00	11,110.00
1994/01 Sub-Total			0.00	0.00	0.00	0.00	-1,500.00	110.00	-1,390.00	294,610.00
1994/02	1994/02	12345678532					-1,500.00		-1,500.00	283,500.00
	1997/08	12345678901						-101.00	-101.00	7,899.00
1994/02 Sub-Total			0.00	0.00	0.00	0.00	-1,500.00	-101.00	-1,601.00	291,399.00
1994 Annual	1996/04	12345678804	2,000.00	-4,000.00	8,500.00				-10,700.00	-10,700.00
	1997/08	12345678901	-1,000.00					-60.00	-6,060.00	-6,060.00
			1,000.00	-4,000.00	8,500.00	0.00	0.00	-60.00	-16,760.00	-16,760.00
1994 Total			$1,000.00	-$4,000.00	$8,500.00	$0.00	-$3,000.00	-$51.00	-$19,751.00	$569,249.00

Reference Number: 1234567

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RESOURCE DEVELOPMENT

1997/08 BILLING PERIOD DETAIL – CURRENT PERIOD CHARGES

ROYALTY PAYER INFORMATION
CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION
ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

Production Period	Charge Type	Automated Charges $	Manual Charges $	Total Charges $
1997/08	Crown Royalty	250,000.00		250,000.00
	Enhanced Oil Recovery Operating Cost Adjustment	50,000.00		50,000.00
	Provisional Royalty Assessment	25,000.00		25,000.00
	Penalties	5,000.00		5,000.00
	Monthly Capital Cost Deduction	-15,000.00		-15,000.00
	Monthly Custom Processing Fee Deduction	-5,000.00		-5,000.00
	Injection Credits	-25,000.00		-25,000.00
	Other Financial Transactions		-1,500.00	-1,500.00
CURRENT PERIOD SUB-TOTAL		285,000.00	-1,500.00	283,500.00

TOTAL CURRENT PERIOD CHARGE: $283,500.00

25.5 Crown Gas Royalty Detail

CROWN ROYALTY DETAIL

PURPOSE

The *Crown Royalty Detail* is the Department's monthly calculation of net Crown natural gas royalty before consideration of corporate items. Royalty clients who do not wish to receive this information should contact the Client Services Help Desk (*Refer to Section 9*).

TIMING

The Department issues a Crown Royalty Detail to each royalty client that has Crown natural gas royalty transactions in a Billing Period, as part of the package that includes the *Invoice*, on or before the last day of the second month following the *production month* to which the Invoice relates.

DESCRIPTION OF ENTRIES

The Crown Royalty Detail will report all new and amended gas and gas product volumes allocated to the royalty client on the OAS. It will also include volume reassignments from other royalty clients as reflected on the RMF2 — Reassignment of volumes Setup/Change form. Volumes will be reported by:

- Royalty Client
  - EUB Facility
  - Production Month
  - Charge Types
  - Stream ID *(Well/Well Group/Unit/Injection Scheme)*

The Crown Royalty Detail consists of two parts:

- Crown Royalty Detail Calculation (CRDC); *and*
- Crown Royalty Detail Volumetric (CRDV).

The CRDC picks the Volumetric Total Quantity from the CRDV and goes through a process to arrive at:

- Crown Royalty Share;
- Gross Royalty;
- Operating Costs;
- Charge Totals; *and*
- Prior Period Interest.

The CRDV picks the information from the source documents (OAS and RMF2) and goes through a process to arrive at the royalty client's Volumetric Total Quantity that is liable to royalty calculation.

The charge types reported on the Detail Calculation and Volumetric statements are:

- Crown Royalty;
- Injection Credits;
- Enhanced Oil Recovery Operating Cost Adjustment;
- Crown Royalty Paid Bank Settlement;
- Crown Royalty Inventory Settlement; *and*
- Provisional Royalty Assessments.

How to Calculate Blended Crown Royalty Rate

For royalty client's information, the Blended Crown Royalty Rate which appears on the Crown Royalty Detail Calculation statement *(field 4.5)* is illustrated by the following example:

Sample Month: January 1994
Stream Type: Unit
Stream ID: 12345
January 1994 Production Vintage: 44.03% New Gas
55.97% Old Gas

A. Calculation of Old Gas Royalty Rate (R%)

January 1994 Old Gas Select Price (SP) = \$0.338 *(see Information Bulletin containing January 1994 information)*

January 1994 Gas Par Price (GPP) = \$2.06 *(see Information Bulletin containing January 1994 information)*

Calculation Formula *(see Section 4.9.4)*

$$R\% = \frac{15(SP) + 40(GPP - SP)}{GPP}$$

$$= \frac{15(0.338) + 40(2.06 - 0.338)}{2.06}$$

$$= \frac{5.07 + 68.88}{2.06}$$

$$= 35.89805 \quad \text{Subject to maximum of 35\%}$$

$$= \underline{\underline{35.00000\%}}$$

B. Calculation of New Gas Royalty Rate (R%)

January 1994 New Gas Select Price (SP) = $1.124 (*see Information Bulletin containing January 1994 information)*

January 1994 Gas Par Price (GPP) = $2.06 *(see Information Bulletin containing January 1994 information)*

Calculation Formula *(see Section 4.9.5)*

$$R\% = \frac{15(SP) + 40(GPP - SP)}{GPP}$$

$$= \frac{15(1.124) + 40(2.06-1.124)}{2.06}$$

$$= \frac{16.86 + 37.44}{2.06}$$

$$= \underline{\underline{26.35922\%}}$$

C. Calculation of Blended Crown Royalty Rate

Base Royalty Rate* (Old Gas Royalty Rate) *(For definition of Base Royalty Rate, please see Appendix N - Glossary)*	= 35.00000%
Vintage Adjustment: (Old Gas Royalty Rate - New Gas Royalty Rate) x New Gas Percentage 35.00000 - 26.35922 = 8.64078 x 44.03%	= (3.80454)
Low Productivity Adjustment: (Refer to the example in *Section 25.6.1*)	= (2.50350)
Blended Crown Royalty Rate	28.69196%

NOTE: (1) THE CROWN ROYALTY SHARE OF THE VOLUMES WILL BE ROUNDED TO THE NEAREST DECIMAL POINT.

(2) FOR THE ROYALTY CLIENTS WHO RECEIVE INVOICE IN UDF FORMAT, THE BLENDED CROWN ROYALTY RATE IS NOT INDICATED ON THE INVOICE. INSTEAD, THE FOLLOWING RATES:

BASE ROYALTY RATE (OLD GAS ROYALTY RATE),
NEW GAS ROYALTY RATE,
NEW GAS PERCENTAGE, *AND*
LOW PRODUCTIVITY ADJUSTMENT

ARE DISCLOSED ON THE INVOICE AND THE CLIENTS ARE EXPECTED TO CALCULATE THEIR OWN BLENDED CROWN ROYALTY RATE. THE CALCULATION IS SIMILAR TO THE ONE ILLUSTRATED ABOVE.

The following pages describe the charges and credits that will be reported on the Crown Royalty Detail Calculation and Volumetric statements.

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NOTE: The numbering of the items on this document is only for cross-referencing to the "Description of Entries" in the Guidelines.
They do not form part of the "Crown Royalty Detail Calculation or Volumetric statements.

CROWN ROYALTY DETAIL CALCULATION

PART 1:

1.2 INVOICE # ☐

1.1 ISSUE DATE ☐☐☐☐ ☐☐ ☐☐
YR MO DA

1.3 ROYALTY CLIENT ☐

1.4 NAME ☐

1.5 FACILITY ☐

1.6 PRODUCTION PERIOD ☐☐☐☐ ☐☐
YR MO

PART 2:

2.1 ROYALTY PAYER CODE ☐

2.2 NAME ☐

2.3 ADDRESS ☐

☐☐ ☐☐☐ ☐☐☐
PROV POSTAL CODE

PART 3:

3.1 ROYALTY PRODUCT	3.2 REFERENCE PRICE $	3.3 PRICE ADJUSTMENT	3.4 RAW GAS FACTOR	3.5 CORPORATE GAS FACTOR	3.6 TRANSPORTATION RATE	3.7 STORAGE RATE	3.8 FRACTIONATION RATE $	3.9 CONVERSION FACTOR	3.10 UNIT OPERATION COST RATE $

PART 4

4.1 ROYALTY PRODUCT	4.2 CLIENT VOLUMETRIC TOTALS		4.3 CROWN INTEREST	4.4 VINTAGE		4.5 CROWN ROYALTY RATE	4.6 CROWN ROYALTY		4.7 GROSS ROYALTY $	4.8 ROYALTY EXEMPTION $	4.9 OPERATING DEDUCTION $	4.10 CHARGE TOTAL $	4.11 INTEREST CHARGE $
	QUANTITY	HEAT		TYPE	%		QUANTITY	HEAT					
4.12 CHARGE TYPE:						4.13 STREAM ID							
4.12 CHARGE TYPE						4.13 STREAM ID:							

Totals:	1 At a facility for each production month, totals by charge type. 2 Summary totals by charge type for each owner. 3. Summary totals by charge type for each Royalty Payer.
Overall Sort:	1. Facility 2. Production Period 3. Stream ID/Charge Type 4. Product
Page Breaks:	Facility and Production Period
Header Information:	Suppressed when the factor is not used in the calculation.
Rounding:	All calculations will be based on full numerical values with rounding only at the charge total level. For reporting purposes, paper documents may reflect truncated quantities

25.5.1 Crown Royalty Detail Calculation Statement

PART 1:ROYALTY CLIENT INFORMATION

1.1 **ISSUE DATE** - The date the Crown Royalty Detail Calculation statement is issued.

1.2 **INVOICE NUMBER** - The unique number assigned by the Department to distinguish a particular Crown Royalty Detail Calculation statement. This number will be the same as that on the Invoice. This number should be quoted when making enquiries about the Crown Royalty Detail Calculation.

1.3 **ROYALTY CLIENT** - The four-character EUB operator code or seven-character ID number assigned by the Department to the royalty client.

1.4 **NAME** - The legal name of the royalty client.

1.5 **FACILITY** - This code identifies the operating cost facility that processed the volumes of the royalty client. The code describes the following:

- the province in which the facility is located;
- the type of facility *(gas plant, gathering system, gas battery or injection facility)*; *and*
- the unique code assigned by the EUB that identifies the facility.

1.6 **PRODUCTION PERIOD** - The year and month for which the quantities are reported on an OAS, and for which the Crown royalty is calculated.

PART 2: ROYALTY PAYER INFORMATION

2.1 **ROYALTY PAYER CODE** - The four-character EUB operator code or a seven-character ID number assigned by the Department to the royalty payer. The royalty payer is recognised by the Department (upon royalty client's instructions) as being responsible to discharge the royalty obligations of the royalty client. A royalty client can also be a royalty payer.

2.2 **NAME** - The legal name of the royalty payer.

2.3 **ADDRESS** - The full mailing address of the royalty payer identified in *fields 2.1 and 2.2.*

PART 3: DATA COMPONENT

3.1 **ROYALTY PRODUCT** - The code used to describe the product on which Crown royalty is calculated *(corresponds to the code used on the source OAS)*. A detailed summary of the *PRODUCTS* and its usage is as follows:

Product Name	Product Code	Unit of Measure	Used on OAS	Used on Cr. Roy. Detail
Condensate	COND	m^3	COND	
Oil	OIL	m^3		
Carbon Dioxide	CO_2	10^3m^3	CO_2	
Nitrogen	N_2	10^3m^3	N_2	
Oxygen	O_2	10^3m^3	O_2	

Product Name	Product Code	Unit of Measure	Used on OAS	Used on Cr. Roy. Detail
Gas	GAS	10^3m^3	GAS	GAS
Ethane Spec	C2-SP	m^3	C2-SP	C2-SP
Propane Spec	C3-SP	m^3	C3-SP	C3-SP
Butane-Spec	C4-SP	m^3	C4-SP	C4-SP
Iso-Butane	IC4-SP	m^3	IC4-SP	C4-SP
Normal-Butane Spec	NC4-SP	m^3	NC4-SP	C4-SP
Pentanes-Spec	C5-SP	m^3	C5-SP	C5-SP
Iso-Pentanes Spec	IC5-SP	m^3	IC5-SP	C5-SP
Normal-Pentanes Spec	NC5-SP	m^3	NC5-SP	C5-SP
Hexane	C6-SP	m^3	C6-SP	C5-SP
Sulphur	S or SUL	Tonnes	S or SUL	S or SUL
Sulphur - Basepad	SBASE	Tonnes	SBASE	S
Sulphur - Block	SBLOC	Tonnes	SBLOC	S
Sulphur - Formed	SFORM	Tonnes	SFORM	S
Sulphur - Molten	SMOLT	Tonnes	SMOLT	S
Sulphur - Prilled	SPRILL	Tonnes	SPRILL	S
Sulphur - Slate	SLATE	Tonnes	SLATE	S
Water	WATER	m^3		
Fresh Water	H_2O	m^3		
LPG	LPG	m^3	LPG	
NGL	NGL	m^3	NGL	
Light Ends (Components lighter than C2 in a mix	LITEMX	m^3	LITEMX	
Ethane Component in Mix	C2-MX	m^3	C2-MX	C2-MX
Propane Component in Mix	C3-MX	m^3	C3-MX	C3-MX
Butane Component in Mix	C4-MX	m^3	C4-MX	C4-MX
Iso-Butane Component in Mix	IC4-MX	m^3	IC4-MX	C4-MX
Normal-Butane Component in Mix	NC4-MX	m^3	NC4-MX	C4-MX
Pentanes Component in Mix	C5-MX	m^3	C5-MX	C5-MX
Iso-Pentanes Component in Mix	IC5-MX	m^3	IC5-MX	C5-MX
Normal-Pentanes Component in Mix	NC5-MX	m^3	NC5-MX	C5-MX
Hexane Component in Mix	C6-MX	m^3	C6-MX	C5-MX

NOTE: CODES FOR PRODUCTS THAT CONTAIN THE SUFFIX -MX ARE THE COMPONENTS WITHIN A MIX STREAM SUCH AS LPGS OR NGLS.

3.2 **REFERENCE PRICE** - The price at which the Crown royalty share of the gas and gas products will be valued to arrive at *Base Royalty. (See 3.5 below regarding Corporate Gas Factor for CAP filers.)* The unit of value will be as follows:

- GJ for gas and ethane;
- M^3 for propane, butane and pentanes; and
- tonnes for sulphur.

NOTE: AFTER A CAP FILER'S CORPORATE AVERAGE PRICE OF GAS FOR A PRODUCTION YEAR IS ESTABLISHED ON THE VA2 FORM AND APPROVED BY THE DEPARTMENT, FIELD 3.2 WILL REPORT THIS PRICE TO VALUE ALL GAS VOLUMES (INCLUDING AMENDMENTS) FOR THIS ROYALTY CLIENT/PRODUCTION YEAR.

3.3 **PRICE ADJUSTMENT** - An adjustment to the *Reference Price* for those royalty clients who are subject to Crown agreements in regard to valuing their Crown royalty volumes.

3.4 **RAW GAS FACTOR** - A deduction from *Reference Price* in respect of raw gas sold by a royalty client in the month. This deduction will be given only upon satisfactory evidence that the raw gas sold was delivered to a processing plant. (*Refer to Section 6.2 and Section 21.5.4 [e].*)

3.5 **CORPORATE GAS FACTOR** - The factor by which the Department either increases or decreases the *Reference Price* to determine the price at which to value the monthly Crown royalty volumes of those royalty clients who have elected Corporate Average Price. *(Refer to Section 14.4)*

NOTE: AFTER THE CAP FILER'S CORPORATE AVERAGE PRICE OF GAS FOR A PRODUCTION YEAR IS ESTABLISHED ON THE VA2 FORM AND APPROVED BY THE DEPARTMENT, FIELD 3.5 WILL REPORT A CORPORATE GAS FACTOR OF 1.00000 FOR THIS ROYALTY CLIENT/PRODUCTION YEAR.

3.6 **TRANSPORTATION RATE** - The regional *Transportation Allowance* deducted from the *Reference Price* for all *(mix and specs)* propane, butane and pentanes-plus. *(Refer to Section 15.3.1.)*

3.7 **STORAGE RATE** - The 1994 *Storage Allowance* deducted from the *Reference Price* for all propane *(mix and specs)*, butane *(mix and specs)* and pentanes-plus *(mix only)*. There is no storage allowance for specification pentanes-plus. *(Refer to Section 15.3.2.)*

NOTE: EFFECTIVE JANUARY 1995, STORAGE ALLOWANCE IS SET AT $0.00 PER M^3.

3.8 **FRACTIONATION RATE** - The *Fractionation Allowance* deducted from the *Reference Price* for propane *mix*, butane *mix* and pentanes-plus *mix*. *(Refer to Section 15.3.3.)*

3.9 **CONVERSION FACTOR** - The energy adjusted gas equivalent factor used to convert gas, liquids and sulphur volumes to a gas equivalent basis for the purpose of calculating *Allowable Operating Cost* for gas and gas products. *(Refer to Section 16.13.1)*

3.10 **UNIT OPERATING COST RATE (UOCR)** - The rate used to calculate the Operating Cost Allowance for gas and gas products. This UOCR is tied to the facility indicated on the header information *(see 1.5 above). (The UOCR is established for each of the Plant Types and the Designated Facilities. These are found in Appendix I.)* UOCR will not be given to the Reference Price filers on raw gas sales, which are eligible for 80% Reference Price valuation. Also, UOCR will not be given to the CAP filers on deemed raw gas sales which are used as off-site fuel or which are delivered to out-of-province facilities for processing.

EXCEPTION: FOR AN EOR OPERATING COST ADJUSTMENT "CHARGE TYPE", THE HEADER FACILITY WILL BE AN INJECTION FACILITY, BUT THE OPERATING COST RATE WILL BE THE ONE APPLICABLE TO THE PLANT THAT PROCESSES THE PRODUCTION VOLUMES. THE ROYALTY CLIENT WILL BE MADE AWARE OF THE PROCESSING PLANT AND THE UOCR USED.

PART 4: CROWN ROYALTY CHARGE CALCULATION

4.1 ROYALTY PRODUCT - *(See 3.1 above.)*

4.2 CLIENT VOLUMETRIC TOTALS

QUANTITY - The quantity (expressed in 10^3m^3) of the product on which Crown royalty is determined. It is derived from the *Source Document Details (see 3.12, under Crown Royalty Detail Volumetric statement [Section 25.5.2] that follows).* For unit of measurement information, please refer to 3.1 above.

HEAT - The heat content *(expressed in GJ)* of the quantity of gas and ethane reported here. *(Ethane, which is in m^3, is converted to GJ by using a factor of 0.28132, and then multiplying the result by 66.065.)*

4.3 **CROWN INTEREST** - The Crown interest share of the product produced from Crown lands by the royalty client. *(Expressed as a percentage, to seven decimal places. Refer to Section 4.5.)*

4.4 VINTAGE

TYPE - The vintage of the Crown gas, ethane and pentanes-plus on which royalty rate is determined. The vintage is either *new* or *old.*

% - The percentage of the Crown gas, ethane and pentanes-plus which is new. If the vintage is new, then the percentage displayed will be 100.00%. If the vintage is old, then the percentage shown will be 0.00%. The applicable percentage will be displayed for commingled vintage.

4.5 **CROWN ROYALTY RATE** - The rate used to calculate Crown royalty for gas and gas products. For gas, ethane and pentanes-plus, this rate is derived after taking into consideration the vintage and low productivity allowance. For the rest of the products, the established rates are used. *(Expressed as a percentage to five decimal places.*

4.6 CROWN ROYALTY

QUANTITY - Crown royalty quantity (in 10^3m^3) derived by multiplying the Crown interest and the Crown royalty rate to the *Client Volumetric Total Quantity indicated in 4.2 above.*

HEAT - Crown royalty quantity (in GJ) derived by multiplying the Crown interest and the Crown royalty rate to the *Client Volumetric Total Heat indicated in 4.2 above*.

4.7 **GROSS ROYALTY** - The dollar value of the Crown royalty share of gas and gas products. The gross royalty is derived by multiplying the *Crown Royalty Quantity/Heat (from 4.6 above)* by the *adjusted Reference Price,* which is the price derived by applying to the Reference Price all the relevant adjustments indicated in *Part 3* of Crown Royalty Detail Calculation statement.

4.8 **ROYALTY EXEMPTION** - An adjustment to the gross royalty in respect of royalty exemptions granted to the royalty client under the various *Incentive Programs. (Refer to Section 5.1.)*

4.9 **OPERATING DEDUCTION** - The amount deducted from *Gross Royalty* after *Royalty Exemption* to arrive at *Crown Royalty Charge Total.* Crown Royalty Quantity (10^3m^3) in *field 4.6* multiplied by conversion factor in *field 3.9* multiplied by UOCR in *field 3.10* equals the operating cost deduction amount.

4.10 **CHARGE TOTAL** - The total charge to the royalty client by products under the charge type and stream ID indicated in *fields 4.12 and 4.13.*

4.11 **INTEREST CHARGE** - A prior period interest charge for each product under the stream ID indicated here. A negative interest amount is a credit to the royalty client. The sum of all prior period interest amounts for the royalty payer is carried forward and reported as *"Interest: Prior Period"* on the *Invoice.*

4.12 **CHARGE TYPE** - The type of charge for which a royalty calculation is done. There are six charge types: *Crown Royalty, Injection Credits, EOR Operating Cost Adjustment, Provisional Royalty Assessment, Crown Royalty Paid Bank Settlement* and *Crown Royalty Inventory Settlement.* The sum of each of the charge type for the royalty payer is reported on the invoice.

4.13 **STREAM ID** - To identify the source from which the production volumes came from. The first two letters identify the province. The next two letters identify the stream type. It could be *WI (single well), WG (well group), UN (unit)* or an *IS (injection scheme).* The remainder relates to the stream ID code assigned by EUB or the Department.

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CROWN ROYALTY DETAIL VOLUMETRIC

PART 1:

1.2 INVOICE # ☐

1.1 ISSUE DATE ☐☐☐☐ ☐☐ ☐☐
YR MO DA

1.3 ROYALTY CLIENT ☐

1.4 NAME ☐

1.5 FACILITY ☐

1.6 PRODUCTION PERIOD ☐☐☐☐ ☐☐
YR MO

PART 2:

2.1 ROYALTY PAYER CODE ☐

2.2 NAME ☐

2.3 ADDRESS ☐

☐☐ PROV ☐☐☐ ☐☐☐ POSTAL CODE

PART 3

SOURCE DOCUMENT DETAILS

3.1 ROYALTY PRODUCT	3.2 SOURCE DOCUMENT	3.3 FACILITY	3.4 OPERATOR	3.5 OWNER	3.6 FILING DATE	3.7 ACTIVITY	3.8 PRODUCT	3.9 QUANTITY	3.10 HEAT	3.11 ALLOCATOR %	3.12 CLIENT VOLUMETRIC TOTALS QUANTITY	HEAT

3.13 CHARGE TYPE: ☐ 3.14 STREAM ID ☐

3.13 CHARGE TYPE ☐ 3.14 STREAM ID: ☐

25.5.2 Crown Royalty Detail Volumetric Statement

PART 1 & PART 2:

PART 1 and PART 2 are identical to the Crown Royalty Detail Calculation statement (CRDC).

PART 3: SOURCE DOCUMENT DETAILS

3.1 **ROYALTY PRODUCT** - *This is identical to 3.1 under the Crown Royalty Detail Calculation statement.*

3.2 **SOURCE DOCUMENT** - This indicates the document type that was the source that provided the information for royalty calculation (e.g., OAS).

3.3 **FACILITY** - The *Reporting Facility* for the *charge type* and the *stream ID*. The facility identified here is the one indicated on the source document in the header information.

3.4 **OPERATOR** - The operator identified here is the *Operator* of the facility mentioned in 3.3 above, and is the same as the one indicated on the source document's header information.

3.5 **OWNER** - The royalty client who is allocated volumes on the source document.

3.6 **FILING DATE** - The date on which the source document was filed. This date is used to determine the most current version when dealing with amendments.

3.7 **ACTIVITY** - The term used to describe the activity that triggered the calculation of Crown royalty. It corresponds to the term used on the source OAS to which the volumes apply. Royalty liable quantities on OAS are triggered depending on this column's transactions. *(Refer to Section 21.6.)*

3.8 **PRODUCT** - The product code indicated on the source document. This also refers to the product in its various components. For royalty calculation purposes, all the various components will be rolled up under the respective product code, as indicated in 3.1 of the CRDC description of entries.

3.9 **QUANTITY** - The quantity reported on the source document related to the activity and product. The unit of measurement is indicated in 3.1 of the CRDC description of entries.

3.10 **HEAT** - The reported heat content in GJ for gas.

3.11 **ALLOCATOR %** - The percentage of volumes allocated on the *RMF2* to the royalty client, by the assignor whose ID is identified in 3.5 above.

3.12 **CLIENT VOLUMETRIC TOTALS** - The royalty client's royalty liable quantity and applicable heat for the gas and gas products. These are carried forward to the CRDC statement and reported under the *"Client Volumetric Totals"* in *column 4.2.*

3.13 &
3.14 *These are identical to 4.12 and 4.13 under the CRDC statement.*

INFORMATION ON AMENDMENTS

1) Since an OAS amendment is a full form replacement, the Crown Royalty Detail Calculation statement will show a reversal of all previous charges resulting from the previous OAS, and creation of new charges resulting from the current amended OAS.
2) All other types of amendments will be communicated to the royalty client only if it results in changes to the volumes or dollars shown on the previous Crown Royalty Detail Calculation or volumetric statement.

25.6 Other Supporting Schedules

The *Invoice* and the *Crown Royalty Detail* statement are supplemented by a number of supporting schedules that provide detailed calculations and information on elements of Crown natural gas royalty that are not common to all royalty clients. Supporting schedules are provided for:

- low productivity well allowances Crown royalty calculation *(refer to Section 25.6.1)*;
- Crown royalty exemption calculation *(refer to Section 25.6.2)*;
- penalties;
- annual adjustments; *and*
- other corporate items if required.

The information provided in the supporting schedules is referenced to the source calculation on the Invoice and the Crown Royalty Detail statement. A schedule may be issued only for a month in which there is activity for the relevant element of Crown royalty.

25.6.1 Low Productivity

LOW PRODUCTIVITY CALCULATION

PURPOSE

The low productivity calculation is a monthly activity showing how the low productivity adjustment rate is derived. This information will accompany the Crown Royalty Detail statements for all royalty clients. Clients who do not want low productivity calculation detail must submit a written request to the Client Services Help Desk.

LOW PRODUCTIVITY APPLICATION

Effective January 1994, Crown volumes will be subjected to base royalty rate (i.e., old gas royalty rate). If applicable, an adjustment for low productivity and vintage will be made to the base royalty rate to arrive at the Crown royalty rate. This rate is shown in *field 4.5* of the Crown Royalty Detail Calculation statement. The low productivity calculation statement will show the low productivity adjustment rate to be deducted from the base royalty rate.

An example of Low Productivity calculation is included in this section for royalty clients' information.

DESCRIPTION OF ENTRIES

The items appearing on "Example of Low Productivity Calculation" statement are self-explanatory; however, Old Low Productivity and New Low Productivity royalty factors and adjustment volumes are calculated as follows:

LOW PRODUCTIVITY CALCULATION FOR OLD GAS (WELL 03-16 IN THE EXAMPLE ON PAGE 25-38)

Old Low Productivity Royalty Factor % (R%)

January 1994 Actual Old Gas Royalty Rate = 35% (RC) *(Refer to Information Bulletin showing January 1994 information)*

Average Daily Production of Gas = 10.4943 10^3m^3 (ADP) (Rounded to 10.5 in the example)

Formula: *(Refer to Section 4.9.6)*

$$R\% = \frac{(RC - 5\%) \times (16.9 - ADP)^2}{16.9^2}$$

$$= \frac{(35 - 5) \times (16.9 - 10.4943)^2}{285.61}$$

$$= \frac{30 \times 41.033}{285.61}$$

$$= \underline{\underline{4.31004\%}}$$

Old Low Productivity Adjustment (10^3m^3)

Old Vintage = 55.97%

Production = 115.0 10^3m^3

Old Gas Low Productivity Royalty Factor = 4.31004%

Adjustment =

55.97% *...multiplied by...* 115.0 10^3m^3 *...multiplied by...* 4.31004% = 2.77418 10^3m^3

LOW PRODUCTIVITY CALCULATION FOR NEW GAS (WELL 03-16 IN THE EXAMPLE NEXT PAGE)

New Low Productivity Royalty Factor % (R%)

January 1994 Actual New Gas Royalty Rate = 26.35922% (RC) *(Refer to Information Bulletin showing January 1994 information)*

Average Daily Production of Gas = 10.4943 10^3m^3 (ADP)

Formula: *(Refer to Section 4.9.6)*

$$R\% = \frac{(RC - 5\%) \times (16.9 - ADP)^2}{16.9^2}$$

$$= \frac{(26.35922 - 5) \times (16.9 - 10.4943)^2}{285.61}$$

$$= \frac{21.35922 \times 41.033}{285.61}$$

$$= \underline{\underline{3.06864\%}}$$

New Low Productivity Adjustment (10^3m^3)

New Vintage = 44.03%

Production = 115.0 10^3m^3

New Gas Low Productivity Royalty Factor = 3.06864%

Adjustment =

44.03% *...multiplied by...* 115.0 10^3m^3 *...multiplied by...* 3.06864% = 1.55379 10^3m^3

Example of Low Productivity Calculation

ROYALTY CLIENT INFORMATION

NAME

CODE

ADDRESS

PROV. **POSTAL CODE**

REGULATORY AGENCY INFORMATION

ISSUER

ISSUE DATE **YR.** **MO.** **DY.**

STREAM TYPE: UN
STREAM ID: 12345
GAS VINTAGE TYPE: NEW
GAS VINTAGE PERCENTAGE: 44.03000%
PRODUCTION PERIOD: 1994-01

Well ID	Hours	OIL Production m^3	Daily Average m^3	GAS Production 10^3m^3	Daily Average 10^3m^3	Well Entity %*	Allocated Production	OLD Low Productivity		NEW Low Productivity	
								Royalty Factor (%)	Adjustment (10^3m^3)	Royalty Factor (%)	Adjustment (10^3m^3)
11-09	67			28.2	10.1	100	28.2	4.85484	0.76627	3.45652	0.42918
11-15	237			22.1	2.2	100	22.1	22.58062	2.79308	16.07681	1.56438
10-19	737	2.46	0.08	272.5	8.9	100	272.5	6.76654	10.32020	4.81760	5.78024
11-21	71			19.7	6.7	100	19.7	11.01589	1.21462	7.84302	0.68030
07-23	593			223.6	9.0	100	223.6	6.47342	8.10142	4.60891	4.53752
10-27	601			327.4	12.9	100	327.4	1.69635	3.10850	1.20776	1.74104
09-30	736	2.76	0.09	188.2	6.1	100	188.2	12.16797	12.81719	8.66328	7.17878
11-31	279			66.2	5.7	100	66.2	13.18866	4.88668	9.38998	2.73698
10-33	240			47.8	4.8	100	47.8	15.42954	4.12797	10.98543	2.31203
10-06	687			241.0	8.4	100	241.0	7.55475	10.19043	5.37879	7.70755
06-07	727	3.03	0.10	301.8	10.0	100	301.8	5.05445	8.53785	3.59864	4.78196
06-01	68			46.9	16.6	100	46.9	0.01265	0.00332	0.00901	0.00186
07-26	650			181.3	6.7	100	181.3	10.94072	11.10194	7.78951	6.21808
11-28	687			423.0	14.8	100	423.0	0.47329	1.12053	0.33697	0.62760
12-02	682			433.1	15.2	100	433.1	0.28906	0.70074	0.20581	0.39248
10-04	684			321.2	11.3	100	321.2	3.32918	5.98506	2.37029	3.35217
03-05	690	3.45	0.12	162.4	5.6	100	162.4	13.29700	12.08634	9.46712	6.76944
11-06	47			8.2	4.2	100	8.2	16.97571	0.77911	12.08626	0.43637
06-34	714	4.16	0.14	232.5	7.8	100	232.5	8.66933	11.28142	6.17234	6.31861
11-10	184			3.4	0.4	100	3.4	28.44618	0.54133	20.25294	0.30319
02-14	53			19.0	8.6	100	19.0	7.22951	0.76881	5.14723	9.43060
03-16	263			115.0	10.5	100	115.0	4.31004	2.77418	3.06864	1.55379
Sub-tot[illegible]							3684.5		114.00699		63.85413
Other W[illegible] Production							3420.0		0.00000		0.00000
Total Production							7104.5		114.00699		63.85413
									2.50350%		

$$\text{Low Productivity Adjustment} = \left[\frac{114.00699 + 63.85413}{7104.5} \times 100 \right] = 2.50350\%$$

25.6.2 Royalty Exemption Statement

ROYALTY EXEMPTION STATEMENT

Refer to Section 9

PURPOSE

This statement is to notify the royalty clients of the status of the exemption in regard to the royalty holiday well. This statement will be sent to each royalty client annually, or when the client reaches the dollar or period cap.

DESCRIPTION OF ENTRIES

Since the items appearing on this document are self-explanatory, no further description is considered necessary. *(Refer to Section 5.1.)*

Example of Royalty Exemption Statement

ISSUE DATE: 1995-05-31

ROYALTY CLIENT CODE: ABC

NAME: ABC Oil & Gas

ROYALTY PAYER CODE: ABC

NAME: ABC Oil & Gas

ADDRESS: XXXXXXXXXXXX
Calgary AB X9X 9X9

WELL IDENTIFIER: 000 00 00 000 00 W0 00

ROYALTY EXEMPTION TYPE: Deep Gas Royalty Holiday Program

ROYALTY EXEMPTION EXPIRATION DATE: ☐☐☐☐ ☐☐ ☐☐ (YR MO. DY.)

ELIGIBLE PERIODS: 24

TOTAL PERIODS TAKEN: 23

TOTAL WELL ELIGIBLE EXEMPTION: $45,000.00

TOTAL WELL ELIGIBLE EXEMPTION TAKEN: $45,000.00

REMAINING WELL ELIGIBLE EXEMPTION: $0.00

	TOTAL WELL			ROYALTY CLIENT SHARE	
PRODUCTION PERIOD	EXEMPTION PERIOD	GROSS ROYALTY	ELIGIBLE EXEMPTION	GROSS ROYALTY	ELIGIBLE EXEMPTION
1994-01	1	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-02	2	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-03	3	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-04	4	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-05	5	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-06	6	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-07	7	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-08	8	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-09	9	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-10	10	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-11	11	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1994-12	12	$2,000.00	$2,000.00	$1,000.00	$1,000.00
SUBTOTAL		$24,000.00	$24,000.00	$12,000.00	$12,000.00
1995-01	13	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-02	14	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-03	15	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-04	16	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-05	17	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-06	18	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-07	19	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-08	20	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-09	21	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-10	22	$2,000.00	$2,000.00	$1,000.00	$1,000.00
1995-11	23	$2,000.00	$1,000.00	$1,000.00	$500.00
SUBTOTAL		$22,000.00	$21,000.00	$11,000.00	$10,500.00
TOTAL		$46,000.00	$45,000.00	$23,000.00	$22,500.00

25.7 Annual Capital Cost Allowance Summary And Detail

ANNUAL CAPITAL COST ALLOWANCE SUMMARY AND DETAIL

Refer to Section 9

PURPOSE

The summary provides net capital cost allocation totals at a facility level for a royalty client and production year.

The detail provides:

- capital cost allowance calculation details at a facility cost centre level;
- net capital cost allocation totals based on AC2 and AC3 forms at a facility cost centre level for a royalty client and production year;
- identifies AC2 form departmental recalculations.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

ANNUAL CAPITAL COST ALLOWANCE SUMMARY

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year: 1994

Royalty Payer 1234
Name: Parent Company
Address: XXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported	EUB Facility	Facility Name	Net CCA Allocation ($)
1	2	3	4
Yes	AB-GP-1000	Facility 1	242,119.87
Yes	AB-GP-2000	Facility 2	864,054.08
Royalty Client Total			1,106,173.95

Legend:

1. **"Yes" If detail report contains breakdown information, "No" If not**
2. **EUB facility**
2. **Facility name**
4. **Column 19 facility total from Annual Capital Cost Allowance Detail**

ANNUAL CAPITAL COST ALLOWANCE DETAIL

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year: 1994

Royalty Payer Code: 1234
Name: Parent Company
Address: XXXXXXXXX
Calgary, AB
X9X 9X9

	AC2 Details											AC3 Reallocation						
FCC 1	Opening Cap Cost ($) 2	Capital Additions($) 3	# of Months 4	RUL 5	Depreciation ($) 6	Closing Cap Cost($) 7	Land 8	Avg Spare Parts Inv($) 9	Retirements($) 10	CCA ($) 11	CCA Distrb % 12	% To Client 13	% From Client 15	AC2 Distrb % 16	From Client ID 17	Net Realloc % 18	Net CCA Alloc ($) 19
EUB Facility: AB-GP-1000		**Facility 1**															
00000001	200,000	0	12	10	20,000	180,000	0	40,000	0	54,000	20.00000					0.00000	10,900.00
*00000002	1,000,000	500,000	12	10	150,000	1,350,000	0	300,000	25,000	396,250	0.00000		100.00000	50.00000	PRQ	50.00000	198,125.00
00000003	80,000	20,000	12	5	20,000	80,000	0	20,000	0	35,000	30.00000	100.00000				-30.00000	0.00
*00000004	150,000	0	12	7	21,429	128,571	0	30,000	5,000	51,821	0.00000		50.00000	25.00000	DEF	12.50000	6,477.68
00000005	175,000	0	12	8	21,875	153,125	0	45,000	0	53,234	100.00000	50.00000	50.00000	100.00000	ABC		
												50.00000				-50.00000	26,617.19
Facility Total																	242,119.87
EUB Facility: AB-GP-2000			**Facility 2**														
*00000006	4,000,000	800,000	12	12	400,000	4,400,000	0	1,500,000	25,000	1,280,000	25.00000	20.00000	10.00000	75.00000	DEF	2.50000	352,000.00
*00000007	3,500,000	675,000	12	12	347,917	3,827,083	0	1,200,000	15,000	1,092,448	50.00000	25.00000	50.00000	50.00000	XYZ		
												25.00000					
												50.00000				-25.00000	273,111.98
00000008	2,000,000	0	12	12	166,667	1,833,333	0	600,000	0	544,167	20.00000	50.00000					
												25.00000				-15.00000	27,208.33
00000009	1,500,000	0	12	12	125,000	1,375,000	0	500,000	0	415,625	20.00000					0.00000	83,125.00
00000010	800,000	0	12	6	160,000	640,000	0	150,000	0	290,500	25.00000	100.00000				-25.00000	0.00
00000011	500,000	(5,000)	12	7	70,714	424,286	0	24,286	5,000	148,679	25.00000	20.00000				-5.00000	29,735.72
00000012	675,000	0	12	8	71,875	503,125	0	128,125	0	171,953	50.00000		10.00000	25.00000	PQR		
													20.00000	25.00000	STU	7.50000	98,873.05
Facility Total																	864,054.08

Legend:
1. Facility CC ID
2. AC2: Field 2.2
3. AC2: Field 2.3
4. AC2: number of months from Fields 2.6 and 2.14
5. Remaining Useful Life
6. AC2: Field 2.6; Calculated: ((2+3)/5)*(4/'12' months)
7. AC2: Field 2.7; Calculated: (2+3)*6
8. AC2: Field 2.9
9. AC2: Field 2.10
10. AC2: Field 2.12
11. AC2: Field 2.15; Calculated: 10+6+((((((2+7)/2)+8+9)*0.15)*(4/'12' months))
12. AC2: Field 4.3
13. AC3: Field 2.3
14. AC3: Field 2.1
15. AC3: Field 2.3
16. AC2: Field 4.3
17. AC3: Field 1.4
18. Calculated: - (13*12)+(15*16)
19. Calculated: (12+18)*11

* Capital ;costs have been recalculated

25.7.1 Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Summary And Detail

CAPITAL COST ALLOWANCE RECAPTURE FOR ENHANCED OIL RECOVERY AND ROYALTY PAID BANK SETTLEMENT SUMMARY AND DETAIL

Refer to Section 9

PURPOSE

The summary provides capital cost allowance enhanced oil recovery and royalty paid bank settlement recapture totals at a facility level for a royalty client and production year, and capital cost allowance totals after recaptures at a facility level for a royalty client and production year.

The detail provides:

- capital cost allowance enhanced oil recovery and royalty paid bank settlement recapture calculation details at a product and facility level for a royalty client and production year.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

CAPITAL COST ALLOWANCE RECAPTURE FOR ENHANCED OIL RECOVERY AND ROYALTY PAID BANK SETTLEMENT SUMMARY

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported 1	EUB Facility 2	Facility Name 3	Client CCA ($) 4	EOR Recapture ($) 5	RPBS Recapture ($) 6	Client CCA After EOR and RPBS Recapture ($) 7
Yes	AB-GP-1000	Facility 1	500,000.00	235,084.61	176,594.39	88,321.01
Yes	AB-GP-2000	Facility 2	187,432.11	117,782.60	69,649.51	0.00
Royalty Client Total			687,432.11	352,867.21	246,243.90	88,321.01

Legend

1. "Yes" if detail report contains breakdown information, "No" if not
2. EUB Facility
3. Facility name
4. Column 9 facility total from Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
5. Column 10 facility total from Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
6. Column 11 facility total from Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
7. Column 12 facility total from Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail

Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail Summary

Invoice #: 12345678901

Issue Date:	1995-05-31
Royalty Client:	1234
Name:	Parent Company
Production Year	1994

Royalty Payer code:	1234
Name:	Parent Company XXXXXXXXXXXXXXXXX Calgary, AB X9X 9X9

Product Code	Client EOR Production	Client RPBS Quantities	Client Facility Production	Gas Equivalent Factor	Gas Equivalent Volumes			Client CCA ($)	EOR Recapture ($)	RPBS Recapture ($)	Client CCA After EOR and RPBS Recapture ($)
					EOR Production	RPBS Quantities	Facility Production				
1	2	3	4	5	6	7	8	9	10	11	12
EUB Facility: AB-GP-1000		Facility 1									
C2-SP	230000.0	0.0	500000.0	0.28132	64703.6	0.0	140660.0				
C3-SP	170000.0	170000.0	500000.0	0.27201	46241.7	46241.7	136005.0				
C4-SP	150000.0	150000.0	400000.0	0.23331	34996.5	34996.5	93324.0				
C5-SP	100000.0	125.0	250000.0	0.20570	20570.0	25.7	51425.0				
GAS	1000000.0	800000.0	2000000.0	1.00000	1000000.0	800000.0	2000000.0				
S	9000.0	0.0	100000.0	0.73750	6637.5	0.0	73750.0				
Facility Total					1173149.3	881263.9	2495164.0	500,000.00	235,084.61	176,594.39	88,321.01
EUB Facility: AB-GP-2000		Facility 2									
C5-SP	18.5	8.9	88.4	0.20570	3.8	1.8	18.2				
GAS	7890.1	6123.4	12543.7	1.00000	7890.1	6123.4	12543.7				
Facility Total					7893.9	6125.2	12561.9	187,432.11	117,782.60	69,649.51	0.00

Legend
1. Product code
2. Annual enhanced oil recovery (EOR) production for royalty client from OAS (Indigenous model)
3. Annual royalty paid bank settlement quantities (RPBS) for royalty client
4. Annual facility production for royalty client from OAS
5. Volumetric gas equivalent conversion factor
6. Calculated: 2*5
7. Calculated: 3*5
8. Calculated: 4*5
9. Capital cost allowance (CCA) at facility (after AC3, net of custom processing adjustment factor)
10. Calculated: (6/8)*9
11. Calculated: (7/8)*9(to a maximum of 9-10)
12. Calculated: 9-10-11

25.7.2 Annual Custom Processing (CP) Fees Net Of Operating Costs Summary And Detail

ANNUAL CUSTOM PROCESSING (CP) FEES NET OF OPERATING COSTS SUMMARY AND DETAIL

Refer to Section 9

PURPOSE

The summary provides custom processing operating cost reduction totals at a facility level for a royalty client and production year.

The detail provides:

- custom processing operating cost reduction calculation details based on the AC5 form at a product and facility level for a royalty client and production year and;
- identifies AC5 form Part 3.5 departmental defaults.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

ANNUAL CUSTOM PROCESSING (CP) FEES NET OF OPERATING COSTS SUMMARY

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported	EUB Facility	Facility Name	AC5 Custom Fees Paid ($)	Energy Adjusted Gas Equivalent Volumes	Operating Cost Reduction ($)	CP Net of Operating Costs ($)
1	2	3	4	5	6	7
Yes	AB-GP-1000	Facility 1	1,000,000	35000.0	350,000.00	650,000.00
Yes	AB-GP-2000	Facility 2	200,000	6383.5	95,752.05	104,247.95
Yes	AB-GP-3000	Facility 3	475,000	14770.5	251,098.57	223,901.43
Yes	AB-GP-4000	Facility 4	650,000	22888.3	107,068.05	542,931.95
Royalty Client Total:			2,325,000	79042.3	803,918.67	1,521,081.33

Legend

1. "Yes" if detail report contains breakdown information, "No" if not
2. EUB facility
3. Facility name
4. Column 2 facility total from Annual Custom Processing (CP) Fees Net of Operating Costs Details
5. Column 6 facility total from Annual Custom Processing (CP) Fees Net of Operating Costs Details
6. Column 6 facility total from Annual Custom Processing (CP) Fees Net of Operating Costs Details
7. Column 6 facility total from Annual Custom Processing (CP) Fees Net of Operating Costs Details

ANNUAL CUSTOM PROCESSING (CP) FEES NET OF OPERATING COSTS DETAIL

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Product Code	AC5 Custom Fees Paid ($)	AC5 Processed Volume	Facility Production	Energy Adjusted Gas Equivalent Factor	Energy Adjusted Gas Equivalent Volume	UOCR ($/103m³)	Delayered Rates			Operating Cost Reduction ($)	CP Net of Operating Cost ($)
							Compr	Gather	Proc		
1	2	3	4	5	6	7	8	9	10	11	12
EUB Facility: AB-GP-1000		Facility 1									
GAS			35000.0	1.00000	35000.0						
Facility Total	1,000,000		35000.0		35000.0	10.00				350,000.00	650,000.00
EUB Facility: AB-GP-2000		Facility 2									
C3-MX			1000.0	0.65554	655.5						
C4-MX			1000.0	0.72793	727.9						
GAS			5000.0	1.00000	5000.0						
Facility Total	200,000		7000.0		6383.4	15.00				95,752.05	104,247.95
EUB Facility: AB-GP-3000		Facility 3									
C3-MX	50,000	1,575.0		0.65554	1032.5	*	3.00	5.00	9.00	17,552.08	
C4-MX	100,000	2,700.0		0.72793	1965.4	*	3.00	5.00	9.00	33,411.99	
C5-MX	75,000	2,250.0		0.78783	1772.6	*	3.00	5.00	9.00	30,134.50	
GAS	250,000	10,000.0		1.00000	10000.0	*	3.00	5.00	9.00	170,000.00	
Facility Total	475,000				14770.5					251,098.57	223,901.43
EUB Facility: AB-GP-4000		Facility 4									
C3-MX		2,000.0		0.65554	1311.1		4.00			5,244.32	
C4-MX		2,500.0		0.72793	1819.8		4.00			7,279.30	
C5-MX		3,500.0		0.78783	2757.4			6.00		16,544.43	
GAS	650,000	12,000.0		1.00000	12000.0		4.00			48,000.00	
GAS		5,000.0		1.00000	5000.0			6.00		30,000.00	
Facility Total	650,000				22888.3					107,068.05	542,931.95

Legend
1. AC5: Field 3.3 or OAS product code
2. AC5: Field 2.2 or Field 3.1
3. AC5: Field 3.4
4. Total annual OAS volumes
5. Energy adjusted gas equivalent (EAGE) conversion factor
6. Calculated: 3*5 or 4*5
7. Unit operating cost rate (UOCR), if * indicates no custom services identified in Field 3.5
8 Gathering unit operating cost rate for EUB facility
9 Compressing unit operating cost rate for EUB facility
10. Processing unit operating cost rate for EUB facility
11. Calculated: 6*7 or 6*sum of delayered rates (8+9+10)
12. Calculated: 2-11
*AC5: Field 3.5 left blank

25.7.3 Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Summary And Detail

CUSTOM PROCESSING FEE RECAPTURE FOR ENHANCED OIL RECOVERY AND ROYALTY PAID BANK SETTLEMENT SUMMARY AND DETAIL

Refer to Section 9

PURPOSE

The summary provides custom processing enhanced oil recovery and royalty paid bank settlement recapture totals at a facility level for a royalty client and production year and provides custom processing totals after recaptures at a facility level for a royalty client and production year.

The detail provides:

- custom processing enhanced oil recovery and royalty paid bank settlement recapture calculation details at a product and facility level for a royalty client and production year.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

CUSTOM PROCESSING FEE RECAPTURE FOR ENHANCED OIL RECOVERY AND ROYALTY PAID BANK SETTLEMENT SUMMARY

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported	EUB Facility	Facility Name	CP Net of Operating Costs ($)	EOR Recapture ($)	RPBS Recapture ($)	Client CP After EOR and RPBS Recapture ($)
1	2	3	4	5	6	7
Yes	AB-GP-1000	Facility 1	650,000.00	92,857.14	46,428.57	510,714.29
Yes	AB-GP-2000	Facility 2	104,247.95	20,223.54	0.00	84,024.41
Yes	AB-GP-3000	Facility 3	223,901.43	14,886.71	7,443.35	201,571.37
Yes	AB-GP-4000	Facility 4	542,931.95	431,206.81	111,725.14	0.00
Royalty Client Total:			1,521,081.33	559,174.20	165,597.06	796,310.07

Legend
1. "Yes" if detail report contains breakdown information, "No" if not
2. EUB facility
3. Facility name
4. Column 9 facility total from Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
5. Column 10 facility total from Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
6. Column 11 facility total from Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail
7. Column 12 facility total from Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement Detail

CUSTOM PROCESSING FEE RECAPTURE FOR ENHANCED OIL RECOVERY AND ROYALTY PAID BANK SETTLEMENT DETAIL

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Product Code	Client EOR Production	Client RPBS Quantities	Facility Production	Gas Equivalent Factor	Gas Equivalent Volumes			CP Net of Operating Cost ($)	EOR Recapture ($)	EOR Recapture ($)	Client After EOR & RPBS Recapture ($)
					EOR Production	RPBS Quantities	Facility Production				
1	2	3	4	5	6	7	8	9	10	11	12
EUB Facility: AB-GP-1000		Facility 1									
GAS	5000.0	2500.0	35000.0	1.00000	5000.0	2500.0	35000.0				
Facility Total					5000.0	2500.0	35000.0	650,000.00	92,857.14	46,428.57	510,714.29
EUB Facility: AB-GP-2000		Facility 2									
C3-MX	250.0		1000.0	0.27201	68.0		272.0				
C4-MX			1000.0	0.23331			233.3				
GAS	1000.0		5000.0	1.00000	1000.0		5000.0				
Facility Total					1068.0		5505.3	104,247.95	20,223.54	0.00	84,024.41
EUB Facility: AB-GP-3000		Facility 3									
C3-MX	150.0	75.0	2000.0	0.27201	40.8	20.4	544.0				
C4-MX	200.0	100.0	3000.0	0.23331	46.7	23.3	699.9				
C5-MX	150.0	75.0	2800.0	0.20570	30.9	15.4	576.0				
GAS	1000.0	500.0	15000.0	1.00000	1000.0	500.0	15000.0				
Facility Total					1118.3	559.1	16819.9	223,901.43	14,886.71	7,443.35	201,571.37
EUB Facility: AB-GP-4000		Facility 4									
C3-MX	2500.0		5000.0	0.27201	680.0		1360.1				
C4-MX	2500.0		4000.0	0.23331	583.3		933.2				
C5-MX	2500.0		3500.0	0.20570	514.3		720.0				
GAS	16500.0	5000.0	20000.0	1.00000	16500.0	5000.0	20000.0				
Facility Total					18277.6	5000.0	23073.2	542,931.95	431,207.56	111,724.39	0.00

Legend
1. Product Code
2. OAS: enhanced oil recovery (EOR) volumes
3. Royalty paid bank settlement (RPBS) quantities
4. Total annual OAS volumes
5. Gas equivalent (GE) conversion factor
6. Calculated: 2*5
7. Calculated: 3*5
8. Calculated: 4*5
9. Custom processing fees net of operating costs
10. Calculated: (6/8)*9 (if 9 is positive)
11. Calculated (7/8)*9 (to a maximum of 9-109, if 9 is positive)
12. Calculated: 9-10-11

25.7.4 Corporate Effective Royalty Rate (CERR) Calculation Summary And Detail

Refer to Section 9

CORPORATE EFFECTIVE ROYALTY RATE (CERR) CALCULATION SUMMARY AND DETAIL

PURPOSE

The summary provides:

- the corporate effective royalty rate and the royalty client receiving the rate for a production year.
- the Crown royalty values and corporate values by facility before adjustments for the royalty client and production year.
- the proprietary waiver and annual co-generation adjustments for the royalty client and production year.
- the Crown royalty value and corporate value totals after adjustments for the royalty client and production year.
- the go-forward estimate corporate effective royalty rate and all of the royalty clients receiving the rate.

The detail provides:

- the Crown royalty value and corporate value calculation details by production period, product and facility for the royalty client and applicable production periods.

DESCRIPTION OF ENTRIES

Since the items appearing on this document are self-explanatory, no further description is considered necessary.

CORPORATE EFFECTIVE ROYALTY RATE (CERR) AMALGAMATION / CONSOLIDATION SUMMARY (SIMPLE)

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Royalty Clients Contributing to CERR for 1234		Numerator	Denominator
Royalty Client	Royalty Client Name	Crown Royalty Value After Adjustments ($)	Corporate Value After Adjustments ($)
1	2	3	4
1234	Parent Company	105,840,000.00	493,760,000.00
2345	Child Company	10,000,000.00	50,000,000.00
Total		115,840,000.00	543,760,000.00
Corporate Effective Royalty Rate 5			0.2130352

Royalty Clients Receiving CERR	
Royalty Client	Name
1234	Parent Company
2345	Child Company

Go-forward Estimate Corporate Effective Roaylty Rate 6	0.2368849

Royalty Clients Receiving Go-forward Estimate CERR	
Royalty Client	Name
1234	Parent Company
2345	Child Company

Simple A/C Legend

1. Royalty client
2. Royalty client name
3. Column 4 total from summary report
4. Column 5 total from summary report
5. Calculated: 3/4
6. Go-forward CERR for current year

CORPORATE EFFECTIVE ROYALTY RATE (CERR) CALCULATION SUMMARY (WITH CERR)

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported	EUB Facility	Facility Name	Numerator Crown Royalty Value ($)	Denominator Corporate Value ($)
1	2	3	4	5
Yes	AB-GP-1000	Facility 1	98,690,000.00	470,760,000.00
Yes	AB-GP-2000	Facility 2	7,500,000.00	24,000,000.00
Royalty Client total Before Adjustments			106,190,000.00	494,760,000.00
	Proprietary Waiver Adjustment		(100,000.00)	
	Annual Co-generation Adjustment		(250,000.00)	(1,000,000.00)
Royalty Client Total After Adjustments			105,840,000.00	493,760,000.00
Corporate Effective Royalty Rate 6				0.2143552

Royalty Client Receiving CERR	
Royalty Client	Name
1234	Parent Company

Go-forward Estimate Corporate Effective Royalty Rate 7	0.2143552

Royalty Clients Receiving Go-forward Estimate CERR	
Royalty Client	Name
1234	Parent Company

With CERR Legend

1. "Yes" if detail report contains breakdown information, "No" if not
2. EUB facility
3. Facility name
4. Column 8 facility total from Corporate Effective Royalty Rate (CERR) Calculation Detail
5. Column 14 facility total from Corporate Effective Royalty Rate (CERR) Calculation Detail
6. Calculated: royalty client total (Crown royalty value / corporate value)
7. Go-forward CERR for current year. Identified only in initial annual billing period

CORPORATE EFFECTIVE ROYALTY RATE (CERR) CALCULATION SUMMARY (WITHOUT CERR)

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Supporting Details Reported	EUB Facility	Facility Name	Numerator	Denominator
			Crown Royalty Value ($)	Corporate Value ($)
3	1	2	4	5
Yes	AB-GP-1000	Facility 1	98,690,000.00	470,760,000.00
Yes	AB-GP-2000	Facility 2	7,500,000.00	24,000,000.00
Royalty Client total Before Adjustments			106,190,000.00	494,760,000.00
	Proprietary Waiver Adjustment		(100,000.00)	
	Annual Co-generation Adjustment		(250,000.00)	(1,000,000.00)
Royalty Client Total After Adjustments			105,840,000.00	493,760,000.00

Without CERR Legend

1. "Yes" if detail report contains breakdown information, "No" if not
2. EUB facility
3. Facility name
4. Column 8 facility total from Corporate Effective Royalty Rate (CERR) Calculation Detail
5. Column 14 facility total from Corporate Effective Royalty Rate (CERR) Calculation Detail

CORPORATE EFFECTIVE ROYALTY RATE (CERR) AMALGAMATION / CONSOLIDATION SUMMARY (COMPLEX)

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Royalty Clients Contributing to Actual CERR for 1234				
Royalty Client	Royalty Client Name	Weighting Factor	Individual CERR	Weighted CERR
1	2	3	4	5
1234	Parent Company	6/12	0.2130352	0.1065176
3456	Other Company	6/12	0.2500000	0.1250000
Actual Corporate Effective Royalty Rate 6				0.2315176

Royalty Clients Receiving CERR	
Royalty Client	Name
1234	Parent Company

Royalty Clients Contributing to Individual CERR for 1234		Numerator	Denominator
Royalty Client	Royalty Client Name	Crown Royalty Value After Adjustments ($)	Corporate Value After Adjustments ($)
7	8	9	10
1234	Parent Company	105,840,000.00	493,760,000.00
2345	Child Company	10,000,000.00	50,000,000.00
Total		115,840,000.00	543,760,000.00

Individual Corporate Effective Royalty Rate for 1234 11	0.2130352
Go-forward Estimate Corporate Effective Royalty Rate 12	0.2368849

In the year an amalgamation or consolidation becomes effective or terminated, the go-forward CERR will not match the CERR.

Royalty Clients Contributing to Individual CERR for 1234	
Royalty Client	Name
1234	Parent Company
2345	Child Company
3456	Other Company

Complex A/C Legend

1. Royalty client
2. Royalty client name
3. The weighting the individual CERR received based on amalgamation and consolidation effective and/or termination dates
4. The individual CERR for the royalty client
5. Calculated: 8*9
6. Sum of the weighted CERR
7. Royalty Client
8. Royalty client name
9. Column 3 total from Corporate Effective Royalty Rate (CERR) Calculation Summary (Without CERR) report
10. Column 4 total from Corporate Effective Royalty Rate (CERR) Calculation Summary (Without CERR) report
11. Calculated: Corporate Effective Royalty Rate (CERR) Calculation Summary (Without CERR) report
12. Go-forward CERR for current year Identified only in initial annual billing period.

CORPORATE EFFECTIVE ROYALTY RATE (CERR) CALCULATION DETAIL

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

		Product	Numerator					Denominator					
Production Period	Product Code	Unit Value($/Unit)	CRQ	Royalty Exemption	Cycling CRQ	Net CRQ	Crown Royalty Value ($)	Client Vol Quantity	Ex-Alta Production	Purchased Quantity	Corporate Cycling	Net Corp Production	Corporate Value ($)
1	2	3	4	5	6	7	8	9	10	11	12	13	14
EUB Facility: AB-GP-1000		Facility 1											
1994-01	C2-SP	1.50	500000.0	0.0	0.0	500000.0	750,000.00	2000000.0	0.0	0.0	0.0	2000000.0	3,000,000.00
	C3-SP	50.00	500000.0	150000.0	0.0	350000.0	17,500,000.00	1500000.0	0.0	0.0	0.0	1500000.0	75,000,000.00
	C4-SP	60.00	400000.0	125000.0	0.0	275000.0	16,500,000.00	1200000.0	0.0	0.0	0.0	1200000.0	72,000,000.00
	C5-SP	80.00	250000.0	75000.0	0.0	175000.0	14,000,000.00	900000.0	0.0	0.0	0.0	900000.0	72,000,000.00
	GAS	1.50	2000000.0	300000.0	400000.0	1300000.0	1,950,000.00	8000000.0	1000000.0	1600000.0	2000000.0	8600000.0	12,900,000.00
	GAS(Raw)	1.20	100000.0	0.0	0.0	100000.0	120,000.00	400000.0	0.0	0.0	0.0	400000.0	480,000.00
	S	10.00	100000.0	50000.0	0.0	50000.0	500,000.00	600000.0	0.0	0.0	0.0	600000.0	6,000,000.00
1994-02	C2-SP	1.50	2000000.0	0.0	0.0	1700000.0	2,550,000.00	8000000.0	0.0	0.0	0.0	8000000.0	12,000,000.00
	C3-SP	55.00	400000.0	125000.0	0.0	275000.0	15,125,000.00	1200000.0	0.0	0.0	0.0	1200000.0	66,000,000.00
	C4-SP	65.00	300000.0	125000.0	0.0	175000.0	11,375,000.00	1200000.0	0.0	0.0	0.0	1200000.0	78,000,000.00
	C5-SP	70.00	150000.0	75000.0	0.0	75000.0	5,250,000.00	900000.0	0.0	0.0	0.0	900000.0	63,000,000.00
	GAS	1.50	9000000.0	300000.0	400000.0	8300000.0	12,450,000.00	2000000.0	1000000.0	1600000.0	2000000.0	2600000.0	3,900,000.00
	GAS(Raw)	1.20	100000.0	0.0	0.0	100000.0	120,000.00	400000.0	0.0	0.0	0.0	400000.0	480,000.00
	S	10.00	100000.0	50000.0	0.0	50000.0	500,000.00	600000.0	0.0	0.0	0.0	600000.0	6,000,000.00
Facility Total							98,690,000.00						470,760,000.00
EUB Facility: AB-GP-2000		Facility 2											
1994-01	GAS	1.50	2500000.0	0.0	0.0	2500000.0	3,750,000.00	8000000.0	0.0	0.0	0.0	8000000.0	12,000,000.00
1994-02	GAS	1.50	2500000.0	0.0	0.0	2500000.0	3,750,000.00	8000000.0	0.0	0.0	0.0	8000000.0	12,000,000.00
Facility Total							7,500,000.00						24,000,000.00

Legend

1. Production period
2. Product code
3. Product unit value
   Gas: Residue gas – monthly reference or gas CAP
   Ethane – monthly gas reference or gas CAP
   Raw gas – 80% of monthly reference
   Propane and butane mix: monthly reference price net of transportation and storage and factionation (EPSTA)
   Propane and butane spec: monthly reference price net of transportation and storage
   Pentanes mix: monthly reference price net of transportation and storage and fractionation (EPSTA)
   Pentanes spec: monthly reference price net of transportation
   Sulphur: annual reference price or S-CAP
4. Crown royalty quantities (CRQ)/heat
5. Crown royalty share of royalty exemption volumes
6. Crown royalty share of production delivered to EUB approved cycling schemes
7. Calculated: 4-5-6
8. Calculated: annual sum of monthly 7*3
9. OAS quantity/heat identified on the crown royalty detail statement
10. Non-Alberta production processed in Alberta identified on OAS documents
11. Purchased volumes from OAS included in the purchaser's CERR
12. Corporate production delivered to EUB approved cycling schemes
13. Calculated: 9+10+11-12
14. Calculated 13*3

25.7.5 Annual Capital Cost and Custom Processing Fee Adjustment

ANNUAL CAPITAL COST AND CUSTOM PROCESSING FEE ADJUSTMENT

Refer to Section 9

PURPOSE

This summary provides:

- annual capital cost and custom processing fee adjustment calculation details for a royalty and production year.
- the Crown share of capital cost allowance and custom processing fees.
- a comparison between the monthly estimates and the actual values for capital cost allowance and custom processing fees for a royalty client and production year.
- capital cost allowance and custom processing fee March adjustments for a royalty client and production year.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

ANNUAL CAPITAL COST ADJUSTMENT AND CUSTOM PROCESSING FEE ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

	Capital Cost	Interest	Custom Processing Fee	Interest
1. Capital Cost / Custom Processing Fee Allowance	$1,000,000.00		$550,000.00	
Operating Reduction			$10,000.00	
EOR Recapture	$0.00		$0.00	
RPBS Recapture	$0.00		$0.00	
Net Capital Cost / CP Fee Allowance	$1,000,000.00		$540,000.00	
2. Corporate Effective Royalty Rate	0.2500000		0.2500000	
3. Crown Share	$250,000.00	$5,000.00	$135,000.00	$2,700.00
4. Previous Crown Share of Capital Cost / CP Fee Deduction	$300,000.00	$6,000.00	$122,500.00	$2,450.00
5. Annual Capital Cost / CP Fee Adjustment	($50,000.00)	($1,000.00)	$12,500.00	$250.00

Amendments Legend

1. Annual capital cost allowance after recapture or annual custom processing free allowance after recaptures and operating cost reduction
2. Annual corporate effective royalty rate
3. Calculated: 1*2
4. Previous Crown share capital cost deduction or custom processing (CP) fee deduction obtained from previous calculation
5. Calculated: 3-4

ANNUAL CAPITAL COST ADJUSTMENT AND CUSTOM PROCESSING FEE ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-06-30
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

	Capital Cost	Custom Processing Fee
1. Capital Cost / Custom Processing Fee Allowance	$1,000.000.00	$500,000.00
Operating Reduction		-$10,000.00
EOR Recapture	$0.00	$0.00
RPBS Recapture	$0.00	$0.00
Net Capital Cost / CP Fee Allowance	$1,000,000.00	$490,000.00
2. Corporate Effective Royalty Rate	0.3000000	0.3000000
3. Crown Share	$300,000.00	$147,000.00
4. Monthly Capital Cost / CP Fee Deduction		
1994-01	$24,166.67	$15,000.00
1994-02	$24,166.67	$15,000.00
1994-03	$24,166.67	$15,000.00
1994-04	$24,166.67	$15,000.00
1994-05	$24,166.67	$15,000.00
1994-06	$24,166.66	$15,000.00
1994-07	$24,166.67	$15,000.00
1994-08	$24,166.66	$15,000.00
1994-09	$24,166.67	$15,000.00
1994-10	$24,166.66	$15,000.00
1994-11	$24,166.67	$15,000.00
1994-12	$24,166.66	$15,000.00
Total	$290,000.00	$180,000.00
5 Annual Capital Cost / CP Fee Adjustment	$10,000.00	($33,000.00)
6. Go-forward Capital Cost / CP Fee Estimate for 1995	$1,000,000.00	$490,000.00
7. March Adjustment for Capital Cost / CP Fee for 1995	$26,000.00	$16,000.00

Initial Annual Billing Period Legend

1. Annual capital cost allowance after recaptures or annual custom processing fee allowance after recaptures and operating reduction.
2. Annual corporate effective royalty rate
3. Calculated: 1*2
4. Monthly capital cost deduction or monthly custom processing (CP) fee deduction obtained from the invoice
5. Calculated: 3-4
6. Go-forward capital cost allowance or custom processing fee allowance for the current year
7. March adjustments for capital cost allowance or custom processing fee allowance estimates

25.7.6 Annual Allowable Cost Restriction Adjustment

ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT

Refer to Section 9

PURPOSE

This summary provides:

- annual allowable cost restriction adjustment calculation details for a royalty payer and production year.
- a comparison between the monthly estimates and the actual values for the allowable cost restriction for a royalty payer and production year.
- calculation details for each royalty client contributing to the royalty payer's annual allowable cost restriction adjustment.

DESCRIPTION OF ENTRIES

Since the items appearing on these reports are self-explanatory, no further description is considered necessary.

ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Natural Gas Royalty ($)		Costs ($)					
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Annual CC	Annual CP Fee	Net Royalty Before Cost Restriction ($)	Total Costs ($)	Annual Allowable Cost Restriction ($)
1	2	3	4	5	6	7	8
280,000.00	25,000.00	10,000.00	65,000.00	200,000.00	245,000.00	265,000.00	20,000.00

	Annual Allowable Cost Restriction Adjustment
9. Annual Allowable Cost Restriction	$20,000.00
10. Annual Sum of Monthly Cost Restriction	$200.00
11. Annual Allowable Cost Restriction Adjustment	$19,800.00

Initial Annual Billing Period Legend

1. Crown royalty net of operating costs, transportation, storage and fractionation
2. Actual monthly proprietary waiver
3. Annual co-generation contract adjustment
4. Annual capital cost
5. Annual custom processing fee
6. Calculated: 1-2-3
7. Calculated: 4+5
8. Calculated: 7-6 (If number is negative, set the annual allowable cost restriction to zero.)
9. Annual Allowable Cost Restriction: 8
10. Sum of monthly allowable cost restrictions
11. Calculated: 9-10

ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Natural Gas Royalty ($)		Costs ($)					
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Annual CC	Annual CP Fee	Net Royalty Before Cost Restriction ($)	Total Costs ($)	Annual Allowable Cost Restriction ($)
1	2	3	4	5	6	7	8
280,000.00	25,000.00	10,000.00	225,000.00	35,000.00	245,000.00	260,000.00	15,000.00

	Annual Allowable Cost Restriction Adjustment	Interest
9. Annual Allowable Cost Restriction	$15,000.00	$300.00
10. Annual Sum of Monthly Cost Restriction	$20,000.00	$400.00
11. Annual Allowable Cost Restriction Adjustment	($5,000.00)	($100.00)

Amendments Legend

1. Crown royalty net of operating costs, transportation, storage and fractionation
2. Actual monthly proprietary waiver
3. Annual co-generation contract adjustment
4. Annual capital cost
5. Annual custom processing fee
6. Calculated: 1-2-3
7. Calculated: 4+5
8. Calculated: 7-6 (If number is negative, set the annual allowable cost restriction to zero.)
9. Annual Allowable Cost Restriction: 8
10. Sum of monthly allowable cost restrictions
11. Calculated: 9-10

ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Natural Gas Royalty ($)		Costs ($)					
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Annual CC	Annual CP Fee	Net Royalty Before Cost Restriction ($)	Total Costs ($)	Annual Allowable Cost Restriction ($)
1	2	3	4	5	6	7	8
Royalty Client: 1234		Parent Company					
280,000.00	25,000.00	10,000.00	65,000.00	200,000.00	245,000.00	265,000.00	
Royalty Client: 2345		Child Company					
59,000.00	0.00	0.00	0.00	45,000.00	59,000.00	45,000.00	
Royalty Payer Total					304,000.00	310,000.00	6,000.00

	Annual Allowable Cost Restriction Adjustment	Interest
9. Annual Allowable Cost Restriction	$6,000.00	$120.00
10. Annual Sum of Monthly Cost Restriction	$0.00	$0.00
11. Annual Allowable Cost Restriction Adjustment	$6,000.00	$120.00

Consolidation – Amendments Legend

1. Crown royalty net of operating costs, transportation, storage and fractionation
2. Actual monthly proprietary waiver
3. Annual co-generation contract adjustment
4. Annual capital cost
5. Annual custom processing fee
6. Calculated: 1-2-3
7. Calculated: 4+5
8. Calculated: 7-6 (If number is negative, set the annual allowable cost restriction to zero.)
9. Annual Allowable Cost Restriction: 8
10. Sum of monthly allowable cost restrictions
11. Calculated: 9-10

ANNUAL ALLOWABLE COST RESTRICTION ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company
Production Year 1994

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Natural Gas Royalty ($)		Costs ($)					
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Annual CC	Annual CP Fee	Net Royalty Before Cost Restriction ($)	Total Costs ($)	Annual Allowable Cost Restriction ($)
1	2	3	4	5	6	7	8
Royalty Client: 1234		Parent Company					
280,000.00	25,000.00	10,000.00	65,000.00	200,000.00	245,000.00	265,000.00	
Royalty Client: 2345		Child Company					
59,000.00	0.00	0.00	0.00	15,000.00	59,000.00	15,000.00	
Royalty Payer Total					304,000.00	280,000.00	0.00

	Annual Allowable Cost Restriction Adjustment
9. Annual Allowable Cost Restriction	$0.00
10. Annual Sum of Monthly Cost Restriction	$200.00
11. Annual Allowable Cost Restriction Adjustment	($200.00)

Consolidation – Initial Annual Billing Period Legend

1. Crown royalty net of operating costs, transportation, storage and fractionation
2. Actual monthly proprietary waiver
3. Annual co-generation contract adjustment
4. Annual capital cost
5. Annual custom processing fee
6. Calculated: 1-2-3
7. Calculated: 4+5
8. Calculated: 7-6 (If number is negative, set the annual allowable cost restriction to zero.)
9. Annual Allowable Cost Restriction: 8
10. Sum of monthly allowable cost restrictions
11. Calculated: 9-10

25.7.7 Royalty Deposit Adjustment

ROYALTY DEPOSIT ADJUSTMENT

Refer to Section 9

PURPOSE

This summary provides royalty deposit adjustment calculation details for a royalty payer and calculation details for each royalty client contributing to the royalty payer's royalty deposit adjustment.

DESCRIPTION OF ENTRIES

Since the items appearing on this report are self-explanatory, no further description is considered necessary.

ROYALTY DEPOSIT ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Deposit Adjustment				
Prior Year				
Annual Net Royalty ($)	Number Months Invoiced	New Deposit ($)	Prior Year Deposit ($)	Deposit Adjustment ($)
1a	2a	3a	4a	5a
57,800.00	12	9,633.33	7,000.00	2,633.33

Net Royalty Calculation ($)											
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Injection Credit	Monthly CC Deduction	Monthly CP Fee Deduction	Annual CC Adjustment	Annual CP Fee Adjustment	Royalty Paid Bank Settlement	Monthly Allowable Cost Restriction	Annual Allowable Cost Restriction Adjustment	Annual Net Royalty
1	2	3	4	5	6	7	8	9	10	11	12
125,000.00	0.00	0.00	25,000.00	2,000.00	0.00	200.00	0.00	40,000.00	0.00	0.00	57,800.00

Legend
1a Annual Net Royalty 12
2a Number of months invoiced
3a Calculated ((1a*'12' months)/2a)/'6'
4a Prior year's royalty deposit amount
5a Calculated 3a-4a

1 Crown lroyalty net of operating costs, transportation, storage and fractionation
2 Actual monthly proprietary waiver
3 Annual co-generation contract adjustment
4 Injection credit
5 Monthly capital cost deductions
6 Monthlv custom processing fee deductions
7 Annual capital cost adjustment
8 Annual custom processing fee adjustment
9 Royalty paid bank settlement
10 Monthly allowable cost restrictions
11 Annual allowable cost restriction adjustment
12 Calculated 1-2-3-4-5-6-7-8-9+10+11

ROYALTY DEPOSIT ADJUSTMENT

Invoice #: 12345678901

Issue Date: 1995-05-31

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Deposit Adjustment				
Prior Year				
Annual Net Royalty ($)	Number Months Invoiced	New Deposit ($)	Prior Year Deposit ($)	Deposit Adjustment ($)
1a	2a	3a	4a	5a
57,800.00	12	9,633.33	7,000.00	2,633.33

											Net Royalty Calculation ($)
Crown Royalty	Monthly Proprietary Waiver	Annual Co-gen Contract Adjustment	Injection Credit	Monthly CC Deduction	Monthly CP Fee Deduction	Annual CC Adjustment	Annual CP Fee Adjustment	Royalty Paid Bank Settlement	Monthly Allowable Cost Restriction	Annual Allowable Cost Restriction Adjustment	Annual Net Royalty
1	2	3	4	5	6	7	8	9	10	11	12
Royalty Client 1234		Parent Company									
125,000.00	0.00	0.00	25,000.00	2,000.00	0.00	200.00	0.00	40,000.00	0.00	0.00	57,800.00
Royalty Client 2345		Child Company									
16,250.00	1,030.00	0.00	0.00	1,200.00	1,200.00	100.00	(100.00)	0.00	0.00	0.00	12,850.00
Royalty Payer Total											
141,250.00	1,000.00	0.00	25,000.00	3,200.00	1,200.00	300.00	(100.00)	40,000.00	0.00	0.00	70,650.00

Legend
1a Annual Net Royalty 12
2a Number of months invoiced
3a Calculated ((1a*'12' months)/2a)/'6'
4a Prior year's royalty deposit amount
5a Calculated 3a-4a

1	Crown lroyalty net of operating costs, transportation, storage and fractionation
2	Actual monthly proprietary waiver
3	Annual co-generation contract adjustment
4	Injection credit
5	Monthly capital cost deductions
6	Monthly custom processing fee deductions
7	Annual capital cost adjustment
8	Annual custom processing fee adjustment
9	Royalty paid bank settlement
10	Monthly allowable cost restrictions
11	Annual allowable cost restriction adjustment
12	Calculated 1-2-3-4-5-6-7-8-9+10+11

25.7.8 Royalty Exemption Statement

ROYALTY EXEMPTION STATEMENT

Refer to Section 5

PURPOSE

This summary provides the royalty client's share of the royalty exemption since 1994-01. It also provides the holiday well's exemption since 1994-01.

DESCRIPTION OF ENTRIES

Since the items appearing on this report are self-explanatory, no further description is considered necessary.

ROYALTY EXEMPTION STATEMENT

Invoice #: 12345678901

Issue Date: 1995-05-31
Royalty Client: 1234
Name: Parent Company

Royalty Payer code: 1234
Name: Parent Company
XXXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Royalty Exemption Information	
Well ID 1	000 00 00 000 00 W0 00
Well Operator ID 2	XYZ
Well Operator Name 3	XYZ Oil & Gas
Royalty Exemption type 4	Deep Gas Royalty Holiday Program
Royalty Exemption Expiration Date 5	1996-03-01
Eligible Periods 6	
Total Periods Taken 7	23
Total Well Eligible Exemption 8	$45,000.00
Total Well Eligible Exemption Take 9	$45,000.00
Remaining Well Eligible Exemption 10	$0.00

	Total Well			Royalty Client Share	
Production Period 11	Exemption Period 12	Gross Royalty ($) 13	Eligible Exemption ($) 14	Gross Royalty ($) 15	Eligible Exemption ($) 16
1994-01	1	2,000.00	2,000.00	1,000.00	1,000.00
1994-02	2	2,000.00	2,000.00	1,000.00	1,000.00
1994-03	3	2,000.00	2,000.00	1,000.00	1,000.00
1994-04	4	2,000.00	2,000.00	1,000.00	1,000.00
1994-05	5	2,000.00	2,000.00	1,000.00	1,000.00
1994-06	6	2,000.00	2,000.00	1,000.00	1,000.00
1994-07	7	2,000.00	2,000.00	1,000.00	1,000.00
1994-08	8	2,000.00	2,000.00	1,000.00	1,000.00
1994-09	9	2,000.00	2,000.00	1,000.00	1,000.00
1994-10	10	2,000.00	2,000.00	1,000.00	1,000.00
1994-11	11	2,000.00	2,000.00	1,000.00	1,000.00
1994-12	12	2,000.00	2,000.00	1,000.00	1,000.00
Sub-Total		24,000.00	24,000.00	12,000.00	12,000.00
1995-01	13	2,000.00	2,000.00	1,000.00	1,000.00
1995-02	14	2,000.00	2,000.00	1,000.00	1,000.00
1995-03	15	2,000.00	2,000.00	1,000.00	1,000.00
1995-04	16	2,000.00	2,000.00	1,000.00	1,000.00
1995-05	17	2,000.00	2,000.00	1,000.00	1,000.00
1995-06	18	2,000.00	2,000.00	1,000.00	1,000.00
1995-07	19	2,000.00	2,000.00	1,000.00	1,000.00
1995-08	20	2,000.00	2,000.00	1,000.00	1,000.00
1995-09	21	2,000.00	2,000.00	1,000.00	1,000.00
1995-10	22	2,000.00	2,000.00	1,000.00	500.00
1995-11	23	2,000.00	1,000.00	1,000.00	1,000.00
Sub-Total		22,000.00	21,000.00	21,000.00	10,500.00
Total		46,000.00	45,000.00	23,000.00	22.500.00

Legend
1. Well ID of royalty exemption
2. Well operator ID
3. Well operator name
4. Royalty exemption type
5. Royalty exemption expiration date
6. Eligible periods of royalty exemption
7. Total periods taken from royalty exemption
8. Total well eligible exemption
9. Column 12 total
10. Remaining well eligible exemption
11. Production period
12. Exemption periods
13. Gross royalty for well
14. Eligible exemption for well
15. Gross royalty for royalty client
16. Eligible exemption for royalty client

Note: This report does not include field condensate

26. Enforcing Compliance with Legislation and Policy

26.1 Calculating Provisional Royalty Compensation

Provisional royalty compensation is provided to ensure that the Crown's cash flow from natural gas royalty is maintained as a result of deficient reporting on the OAS. The Facility Operator who submits the OAS is responsible to correct deficient reporting.

The business rules relating to provisional royalty are set out in *Section 10.2.* The purpose of this section is to describe the calculation of provisional royalty compensation.

26.1.1 Accountable Parties

A.R. 351/93
S.21(1)(2)(4)(5)

Companies or individuals who operate any of the following facilities (Facility Operators) are required to submit an Owner Activity Statement (OAS) to the Department each month in which the facility has ***quantities available for sale***[*]:

-a reprocessing plant that is not a *field straddle plant; or*

-a gas processing plant; *or*

-a gas gathering system, *or*

-a gas battery; *or*

-any Facility Operator who is directed by the Department in a particular case to be responsible for specified quantities available for sale.

The Facility Operator is responsible for reporting the quantities available for sale at his facility, and is accountable for any deficiency to the Department.

26.1.2 Provisional Royalty Trigger

The following reporting deficiencies represent a failure to account for quantities (within certain tolerances) available for sale, and will trigger provisional royalty:

A.R. 351/93
S.21(8)

failure to submit an OAS to the Department for quantities available for sale at a facility by the reporting deadline;

IN WHICH CASE, THE DEPARTMENT WILL DEEM THE FACILITY OPERATOR TO HAVE FILED A NIL REPORT.

S.22(1)

an OAS submitted to the Department does not allocate all the quantities available for sale;

IN WHICH CASE, THE DEPARTMENT WILL DEEM THE UNALLOCATED QUANTITIES TO BE ALLOCATED TO THE FACILITY OPERATOR.

S.22(2)

the quantities reported to the EUB on "S" series or equivalent for a facility exceed the quantities reported to the Department on an OAS;

IN WHICH CASE, THE DEPARTMENT WILL DEEM THE EXCESS QUANTITIES TO BE ALLOCATED TO THE FACILITY OPERATOR (THIS WILL INCLUDE THE CONSEQUENCES OF A DEEMED NIL ALLOCATION RESULTING FROM A FAILURE TO SUBMIT AN OAS).

S.22(3)

the quantities reported by the Facility Operator as *purchased* at a facility exceed the quantities reported as *sold* by the Facility Operator(s) of the upstream facilities;

---

[*] ***For definition, please see Appendix N – Glossary***

IN WHICH CASE, THE DEPARTMENT WILL DEEM THE EXCESS QUANTITIES TO BE ALLOCATED TO THE OPERATOR OF THE UPSTREAM FACILITIES.

- the quantities reported to the Department on an OAS document for injection schemes exceed the quantities reported to the EUB on "S" series or equivalent;

IN WHICH CASE, THE DEPARTMENT WILL DEEM THE EXCESS QUANTITIES TO BE ALLOCATED TO THE OPERATOR OF THE INJECTION FACILITY.

26.1.3 Calculating Provisional Royalty Compensation

A.R. 351/93

Where provisional royalty has been triggered, the provisional royalty compensation will be calculated and charged to the royalty account of the Facility Operator, deemed the royalty client, in the following manner:

S.22(1)(2)(3)(4)

- the quantity allocated to the Facility Operator is wholly subject to Crown royalty; *and*
- the rate determined for the Crown royalty share of the subject quantity is 35% for gas and gas products;
- the default factor of 41 will be used to convert 10^3m^3 to GJ; *and*
- the Department will value the Crown royalty share at either:
  - the Gas Reference Price for the production month,
  - 95% of the Pentanes Reference Price for the production month, where the quantities consist of pentanes plus,
  - 95% of the Propane Reference Price for the production month, where the quantities consist of propane,
  - 95% of the Butane Reference Price for the production month, where the quantities consist of butane,
  - 95% of the Pentanes Reference Price for the production month, where the quantities consist of NGL/LPG mix,
  - the Sulphur Default Price for the production month, where the quantities consist of sulphur.
- there will be no deduction for allowable costs.

The 5% reduction of the respective product Reference Price is in lieu of Regional Transportation Allowance, Fractionation Allowance, Storage Allowance and where applicable, Special Pentanes Processing Allowance.

26.2 Collecting Outstanding Accounts

Where an amount has been levied against a royalty client's *Gas Account*, and some or all of that amount has not been paid by the due date specified on the relevant Invoice, the Department will take action to collect the outstanding amount.

The Department's action will be in four stages and will continue until all the outstanding amount is collected. The four stages are:

- balance not paid by the due date *¼Notice issued to royalty client on the Statement of Account*;

  balance outstanding **30 days** *...Potential Recourse Letter issued to royalty client;*
- balance outstanding **60 days** *...Leaseholder Recourse Letter issued to leaseholders, and*

  - *letter to Alberta Corporate Tax to transfer any ARTC refund due the royalty client to the Department*
  - *if the royalty client is named on the lease, the Department will freeze the lease (i.e., the Department will not consent to a sale or transfer of the lease).*
- balance outstanding **90 days** *...Department notifies leaseholders that they have 30 days to make payment or face lease cancellation.*

26.3 Determining Leaseholder Liability

The Department will relate outstanding liabilities to leases and leaseholders in order to apply its collection procedures using the following principles.

If a royalty client against whom the Department has taken action to collect outstanding balances has more than one lease, the Department will determine which leases are subject to the action by:

- allocating the outstanding balance to the royalty client's *Well/Well Group/Unit/Injection Scheme*, to which the default relates;
- allocating the outstanding balance to the well events within the *Well/Well Group/Unit/Injection Scheme* based on EUB production data, adjusted for Crown interest; *and*
- associating the outstanding balance at each well event with the Crown lease agreement for that well event.

26.4 Late Filing Penalties: Production Year 1994

The following penalties will apply on late filing or non-filing of the forms that are required to be submitted under the Natural Gas Royalty Regulation, 1994:

Form	Form Due Date	Form Name	Consequence of Late Filing or Non Filing	Penalized Party	Penalty	Penalty Timing
RMF1	Last day of the month following the production month	Well Group Setup/Change	No Impact	Facility Operator	$1,000/mth from due date	Upon receipt of the form
RMF2	Last day of the third month following the production month	Reassignment of Royalty Volumes	No Impact	Assigning Royalty Client	$1,000/mth from due date	Upon receipt of the written request for retroactive processing.
RMF3	Last day of the month following the production month	Single Well Injection Scheme: - Set Up - Change	Blended Rate No credit given No Impact	Facility Operator	$1,000/mth from due date	Upon receipt of the form

Form	Form Due Date	Form Name	Consequence of Late Filing or Non Filing	Penalized Party	Penalty	Penalty Timing
OAS	15th day of the second month following the production month	Owner Activity Statement	Provisional Assessment	Facility Operator	$1,000/mth from due date until received	Due date of the form
PW1	Last day of the month following the production month unless specified otherwise in the Crown Agreement	Proprietary Gas Royalty Waived	Processed in month received No credit given	N/A	Loss of Interest	N/A
595	June 30 following the production year	Sulphur Emission Control	Processed in month received No credit given	N/A	Loss of Interest	N/A
VA1	For new clients, 15th day of the second month following the production month. For existing clients, June 15, 1994	Gas Valuation Election	Becomes Reference Price filer	N/A	None	N/A
VA2	April 15 following the production year	Corporate Average Price Calculation - Gas	Reverts to Reference Price if not received within 4 months after due date	Royalty client	$1,000/mth from due date. Maximum of $5,000 if not filed within 4 months after due date	Upon due date of the form. Every month of default
VA3	April 15 following the production year	Annual Sulphur Corporate Average Price (S-CAP) Calculation	Default Price used to estimate royalty if not received within 3 months after the due date	Royalty client	$1,000/mth from due date until the receipt of the form Re-calculate using S-CAP	Upon due date of the form Upon receipt of the VA3
VA4	15th day of the second month following the production month	Monthly Sulphur Corporate Average Price (S-CAP) Calculation	Default Price used to estimate royalty	Royalty client	$1,000/mth from due date until the receipt of the form Re-calculate using S-CAP	Due date of the form Upon receipt of VA4

Form	Form Due Date	Form Name	Consequence of Late Filing or Non Filing	Penalized Party	Penalty	Penalty Timing
GR1	Not applicable to new clients. For existing clients, June 15, 1994	Grandfathered Contracts Application	Rejected if late. Reference Price used	N/A	None	N/A
GR2	March 31 following the production year	Annual Grandfathered Contract Sales	Not grandfathered until received. Reverts to Ref. Price if not filed within 4 months after due date; lose right to grandfathering	Royalty client	$1,000/mth from due date $4,000 if not filed within 4 months after the due date	Upon due date of the form After 4 months of default
NGL1	10th day of the second month following the production month	NGL Valuation	Prices and rates calculated without submission	Designated Purchaser	$1,000/mth from due date until the form is received	Due date of the form
AC1	March 1 following the production year	Facility Cost Centre Setup	No impact if changes not reported. No costs given on new facility if not reported	Facility Cost Centre Operator	$1,000/mth from due date	Upon receipt of the form
AC2	April 15 following the production year	Allowable Capital Costs	No costs given in the relevant production year	Facility Cost Centre Operator	$1,000/mth from due date	Upon receipt of the form
AC3	May 15 following the production year	Capital Re-allocations	No changes to capital re-allocations	Royalty client	$1,000/mth from due date	Upon receipt of the form
AC4	March 31 following the production year	Allowable Operating Costs	No costs given in the relevant production year	Designated Facility Cost Centre Operator	$1,000/mth from due date	Upon receipt of the form
AC5	May 15 following the production year	Allowable Custom Processing Fees	No costs given in the relevant production year	Royalty client	$1,000/mth from due date	Upon receipt of the form

Current Late Filing Penalties: Production Year 1995 and Onwards

The following penalties will apply on late filing or non-filing of the forms that are required to be submitted under the Natural Gas Royalty Regulation, 1994:

Form	Form Due Date	Form Name	Consequence of Late Filing or Non Filing	Penalized Party	Penalty	Penalty Timing
RMF1	Last day of the month following the production month	Well Group Setup/Change	No Impact	Facility Operator	None	N/A
RMF2	Last day of the third month following the production month	Reassignment of Royalty Volumes	No Impact	Assigning Royalty Client	None	N/A
RMF3	Last day of the month following the production month	Single Well Injection Scheme: - Set Up - Change	Blended Rate No credit given No Impact	Facility Operator	None	N/A
OAS	15th day of the second month following the production month	Owner Activity Statement	Provisional Assessment	Facility Operator	$1,000/month until received	From Due Date
PW1	Last day of the month following the production month unless specified otherwise in the Crown Agreement	Proprietary Gas Royalty Waived	Processed in month received. No credit given.	N/A	Loss of Interest	N/A
595	June 30 following the production month unless specified otherwise in the Crown Agreement	Sulphur Emission Control	Processed in month received. No Credit given.	N/A	Loss of Interest	N/A
VA1	For new clients, 15th day of the second month following the production month. For existing clients, June 15, 19994.	Gas Valuation Election	Becomes Reference Price filer	N/A	None	N/A
VA2	April 15 following the production year.	Corporate Average Price Calculation - Gas	Reverts to Reference Price if not received within 4 months after due date	Royalty client	$1000 one time/revoke*	From Due Date
VA3	April 15 following the production year.	Annual Sulphur Corporate Average Price (S-CAP) Calculation	Default Price used to estimate royalty if not received within 3 months after the due date.	Royalty client	$1000 one time	From Due Date

Form	Form Due Date	Form Name	Consequence of Late Filing or Non Filing	Penalized Party	Penalty	Penalty Timing
VA4	15th day of the second month following the production month	Monthly Sulphur Corporate Average Price (S-CAP) Calculation	Default Price used to estimate royalty	Royalty client	$100/month until received	From Due Date
GR1	Not applicable to new clients. For existing clients, June 15, 1994.	Grandfathered Contracts Application	Rejected if late. Reference Price used.	N/A	None	N/A
GR2	March 31 following the production year.	Annual Grandfathered Contract Sales	Not grandfathered until received. Reverts to Ref. Price if not filed within 4 months after due due; lose right to grandfathering..	Royalty Client	$1000 for four months/revoke*	From Due Date
NGL1	10th day of the second month following the production month.	NGL Valuation	Prices and rates calculated without submission	Designated Purchaser	$1000/month until received	From Due Date
AC1	March 1 following the production year.	Facility Cost Centre Setup	No impact if changes not reported. No costs given on new facility if not reported.	Facility Cost Centre Operator	None	N/A
AC2	April 15 following the production year.	Allowable Capital Costs.	No costs given in the relevant production year.	Facility Cost Centre Operator	$100/month until received	From Due Date
AC3	May 15 following the production year.	Capital Re-allocations	No changes to capital re-allocations	Royalty Client	None	N/A
AC4	March 31 following the production year.	Allowable Operating Costs	No costs given in the relevant production year.	Designated Facility Cost Centre Operator	$1000/year	From Due Date
NGL1	10th day of the second month following the production month.	NGL Valuation	Prices and rates calculated without submission	Designated Purchaser	$1000/month until received	From Due Date
AC5	May 15 following the production year	Allowable Custom Processing Fees	No costs given in the relevant production year	Royalty Client	$100/month until received	From Due Date

*The valuation election is revoked and the client will default to the Reference Price.

NOTE: 1) FORMS THAT ARE RECEIVED ON TIME, BUT ARE NOT SYSTEM ACCEPTABLE IN ACCORDANCE WITH THE ESTABLISHED EDIT RULE, WILL BE SUBJECT TO PENALTIES IF THESE FORMS ARE RE-SUBMITTED AFTER THE DUE DATE.

2) THE RECEIPT DATE OF THE FORM WILL BE THE DATE WHEN THE DEPARTMENT HAS OFFICIAL CUSTODY.

3) RECEIPT OF THE FORM AT DATA PROCESSING CENTRES DEPEND ON THE AGENCY RELATIONSHIP. IF DATA PROCESSING CENTRE IS AN AGENT OF THE INDUSTRY, THEN ITEM (2) ABOVE PREVAILS.

4) FOR EDI CLIENTS, THE RECEIPT DATE IS WHEN VALUE-ADDED NETWORK (VAN) (E.G., GE) RECEIVED THE TRANSMISSION.

5) IN THE CASE OF MAIL, THE DATE OF RECEIPT IS WHEN THE DEPARTMENT RECEIVES THE DOCUMENTS.

6) THERE WILL BE ONE LATE FILING PENALTY CHARGE PER FORM PER BILLING PERIOD. IF THERE ARE SEVERAL AMENDMENTS OF THE SAME FORM WITHIN ONE BILLING PERIOD, THEN THE PENALTY APPLICABLE TO THE EARLIEST RETROACTIVE EFFECTIVE DATE WILL BE CHARGED.

7) PENALTIES WILL BE CHARGED WHEN FORMS ARE AMENDED RETROACTIVELY AFTER THEIR DUE DATES. THESE FORMS ARE DESCRIBED BELOW:

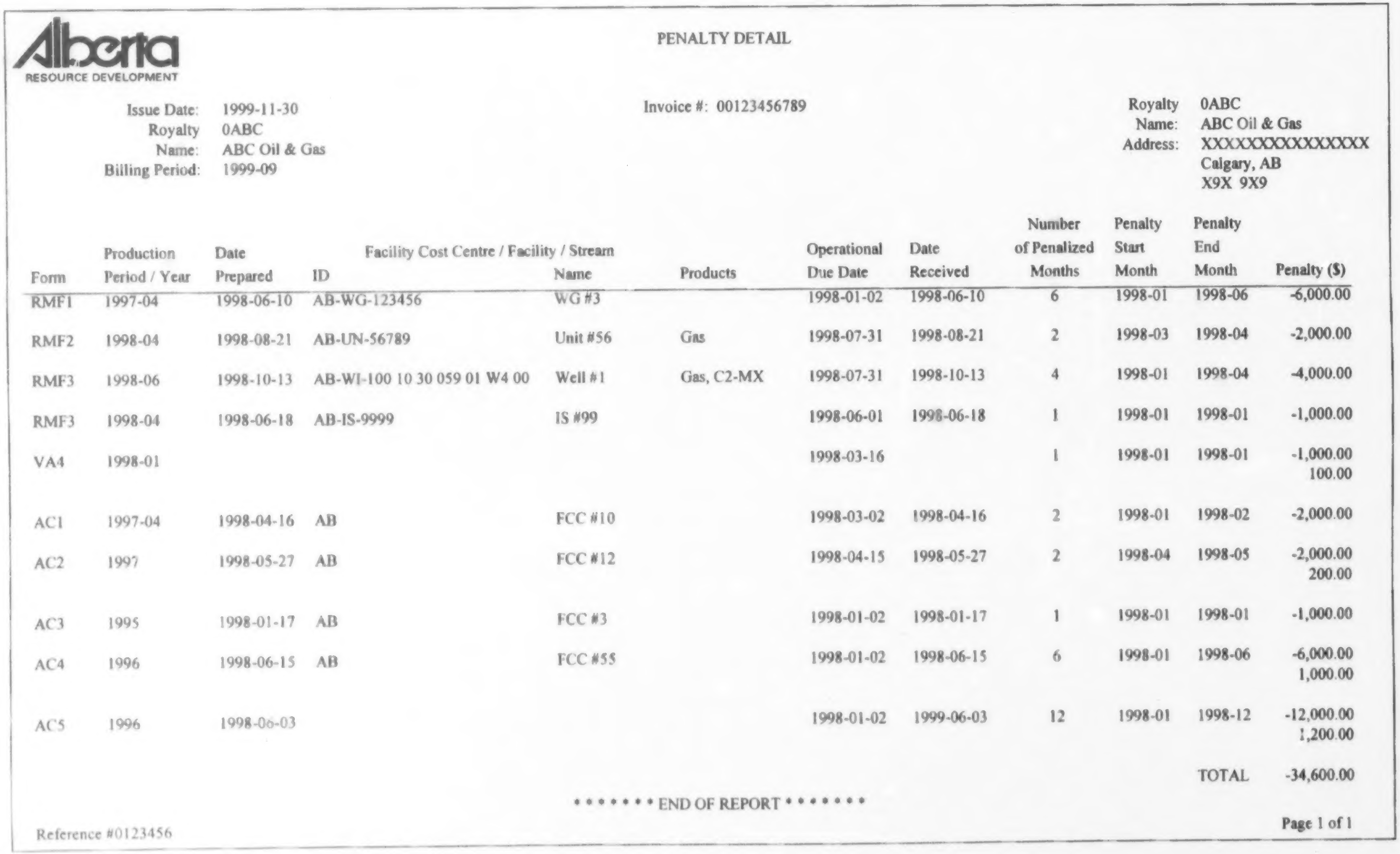
Form	For Production Year 1994 Only Penalties applied on changes to:	Penalty does not apply for changes to:
RMF1	Part 2 and 3	Part 1
RMF2	Part 3, 4 and submission of written request for retroactive processing.	Part 1 and 2
RMF3	Part 2, 3 and 4	Part 1

8) THE DEPARTMENT WILL NOT CHARGE A LATE FILING PENALTY ON FORMS THAT ARE REFILED DUE TO RETROACTIVE RE-VALIDATION.

26.5 Penalty Detail Report

A detailed summary of penalties charged to a royalty client in a billing month will accompany all invoices that show a penalty charge as one of the charge types.

An example of this report is on the next page.



Alberta
RESOURCE DEVELOPMENT

PENALTY DETAIL

Issue Date: 1999-11-30
Royalty Name: 0ABC ABC Oil & Gas
Billing Period: 1999-09

Invoice #: 00123456789

Royalty Name: 0ABC ABC Oil & Gas
Address: XXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Form	Production Period / Year	Date Prepared	Facility Cost Centre / Facility / Stream ID	Facility Cost Centre / Facility / Stream Name	Products	Operational Due Date	Date Received	Number of Penalized Months	Penalty Start Month	Penalty End Month	Penalty ($)
RMF1	1997-04	1998-06-10	AB-WG-123456	WG #3		1998-01-02	1998-06-10	6	1998-01	1998-06	-6,000.00
RMF2	1998-04	1998-08-21	AB-UN-56789	Unit #56	Gas	1998-07-31	1998-08-21	2	1998-03	1998-04	-2,000.00
RMF3	1998-06	1998-10-13	AB-WI-100 10 30 059 01 W4 00	Well #1	Gas, C2-MX	1998-07-31	1998-10-13	4	1998-01	1998-04	-4,000.00
RMF3	1998-04	1998-06-18	AB-IS-9999	IS #99		1998-06-01	1998-06-18	1	1998-01	1998-01	-1,000.00
VA4	1998-01					1998-03-16		1	1998-01	1998-01	-1,000.00 100.00
AC1	1997-04	1998-04-16	AB	FCC #10		1998-03-02	1998-04-16	2	1998-01	1998-02	-2,000.00
AC2	1997	1998-05-27	AB	FCC #12		1998-04-15	1998-05-27	2	1998-04	1998-05	-2,000.00 200.00
AC3	1995	1998-01-17	AB	FCC #3		1998-01-02	1998-01-17	1	1998-01	1998-01	-1,000.00
AC4	1996	1998-06-15	AB	FCC #55		1998-01-02	1998-06-15	6	1998-01	1998-06	-6,000.00 1,000.00
AC5	1996	1998-06-03				1998-01-02	1999-06-03	12	1998-01	1998-12	-12,000.00 1,200.00
										TOTAL	-34,600.00

* * * * * * * END OF REPORT * * * * * * *

Reference #0123456

Page 1 of 1

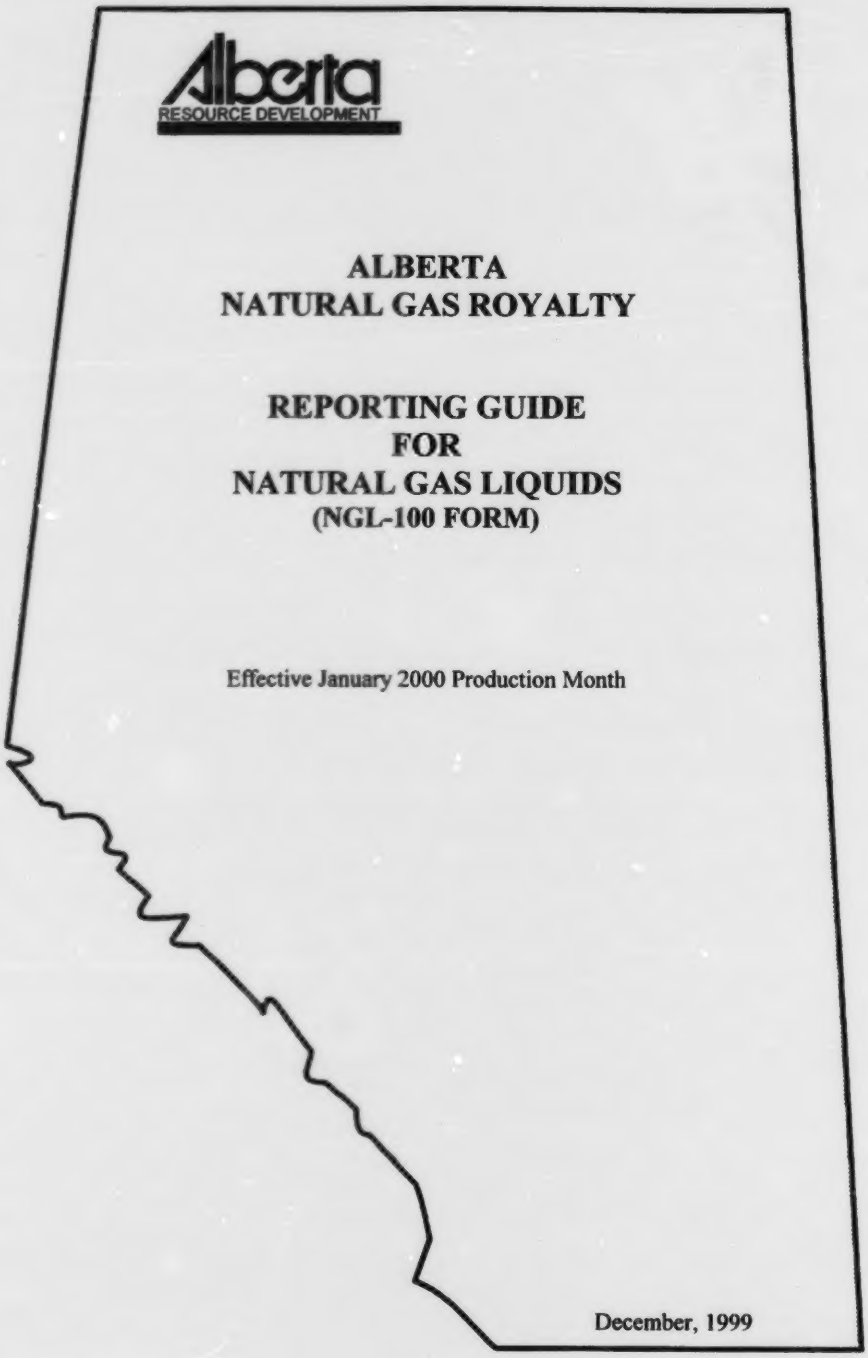
26.6 Default Process

The following defaults will apply when information submitted is inaccurate or inconsistent with the business rules indicated in the Principles and Procedures.

Form	**Default Item**	**Default Situation**	**Default**
AC2	Opening Allowable Capital Cost	If the opening balance does not equal last year's closing, default to closing balance.	Default to previous year's closing balance.
AC2	Months	If the number of months is left blank for either depreciation or return on average capital, default to 12 months	Default to 12 months
AC5	Custom Services Paid	If none of: compression, gathering and processing are chosen, it is assumed that all apply.	Default is the recapture of the total UOCR
Exhibit A	Crown Interest	If an RMF2 was filed, the assignee's Crown interest from the Exhibit A is used. If the assignee is not on the Exhibit A, the assignor's Crown interest is used. If there is no RMF2 and volumes are allocated to a client who is not on the Exhibit A, Crown interest default to values that protect the Crown's position.	Assignor's Crown interest or 100% Crown interest for Royalty and 0% Crown interest for Injection Credits
GR2	Grandfathered Contracts	Received more than 4 months after due date	Contract reverts to Reference Pricing beginning that production year
OAS	Raw Gas	Heat content not reported	41 gigajoules / 10^3M^3
RMF2	Crown Interest	For single wells, if the assignee's Crown interest is not available then the assignor's Crown interest from the RMF3 will be used, if that is not available then Crown interest defaults to values which protect the Crown interest.	Assignor's Crown interest or 100% Crown interest for Royalty and 0% interest for Injection Credits
RMF2	Product Reassignment	If product field is left blank, gas and all products are reassigned.	Default - all products are reassigned
RMF3	Crown Interest	If there is an RMF3 on file and the OAS allocates volumes to a client not listed on the RMF3 for a blended Crown Single well, Well group or Injection Scheme, the Crown interest defaults to protect the Crown's position.	100% Crown interest for royalty and 0% interest for the calculation of Injection Credits
RMF3	WIO%	If product field is left blank, the working interest ownership applies to gas and all products.	Default - all products
VA1	Valuation Method	If form not submitted.	Royalty client is a Reference Price Filer
VA2	Minimum Price for the Corporate Average Price	If CAP prices are significantly lower than reference prices, the calculated CAP defaults to the minimum price.	90% of the weighted average of the monthly Gas References Prices for the year to which the CAP applies

Form	**Default Item**	**Default Situation**	**Default**
VA2	CAP Calculation	Received more than 4 months after due date	Client reverts to Reference pricing beginning that production year
VA2	CAP Calculation	CAP price less than 90% of annual weighted average gas price	Price defaults to minimum 90% of annual weighted average gas price
VA3	S-CAP Calculation	If VA3 forms are not filed, the weighted average unit value of all arm's length sales on all VA3 forms filed is used to value sulphur	Annual Sulphur Default Price is used for valuation
VA3	S-Cap Calculation	VA3 forms are subject to minimum values	Minimum of $0.00
VA3	S-CAP Calculation	Client's arm's length sales are less than 10% of total production	Annual Sulphur Default Price is used for valuation
VA4	S-CAP Calculation - Monthly	If VA4 forms are not filed, the weighted average unit value of all arm's length sales on VA4 forms filed is used to value sulphur	Monthly Sulphur Default Price is used for valuation for all clients not filing a VA4
VA4	S-CAP Calculation - Monthly	If VA4 filing results in a negative price, the minimum price is used.	Monthly Sulphur Price - minimum of $0.00
General	CERR	For new royalty clients, there is no history on which to determine the CERR	The previous year's actual provincial average CERR will be used for current year's CERR estimate
General	Provisional Assessment	If volumes are not allocated to the stream level, the facility operator is assessed for the unallocated volumes	Rate/Prices will default as follows: Crown interest 100%; Royalty rate - 35%; Monthly Ref.Price for gas; 95% of Monthly Reference Price for all gas products except sulphur; Monthly Default Price for Sulphur; No cost allowance will be given.
General	CAP Filers	A client amalgamates with a reference price filer or becomes associated with (75% beneficial interest) a reference price filer	Client reverts to Reference pricing beginning the following production year
General	Corporate Gas Factor	Monthly invoicing uses reference price multiplied by the client's corporate gas factor calculated using	Minimum CGF is 0.9 for existing clients.

Form	Default Item	Default Situation	Default
		the previous year's reported results.	CGF (for first year) is 1.0 for new clients using CAP
General	Allowable Cost Restriction	Monthly allowable costs cannot result in a negative royalty charge.	Allowable costs are reduced by the amount that costs exceeded royalty charges
General	Allowable Cost Restriction	Monthly allowable costs cannot result in a negative royalty charge.	Allowable costs are reduced by the amount that costs exceeded royalty charges
General	Crown Interest	If there is no Crown interest available for a well, the default is 100% Crown interest.	Default 100% Crown Interest
General	Vintage	If vintage is unavailable, the default is new for royalty and for injection credits.	Default - 100% new for royalty and for injection credits



Alberta
RESOURCE DEVELOPMENT

ALBERTA
NATURAL GAS ROYALTY

REPORTING GUIDE FOR NATURAL GAS LIQUIDS
(NGL-100 FORM)

Effective January 2000 Production Month

December, 1999

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REPORTING DEADLINES

WHY DO YOU NEED TO REPORT?

Under Alberta's Crown Royalty system, producers of propane, butanes and pentanes plus pay royalties to the Alberta government based on published reference prices and allowances. This royalty system has been in place since January 1994.

Industry provides the information used to calculate reference prices and allowances. Reports are submitted to the Department of Resource Development under the authority of the Natural Gas Royalty Regulation, 1994, and the Mines and Minerals Act. Gas Valuation staff located in Calgary administer these responsibilities.

Information is provided by companies designated by the Minister as major purchasers of propane, butanes or pentanes plus. Designated purchasers are required to file an NGL-100 form effective with the production month of January 2000.

For delivery months from January 1994 through to December 1999, six designated purchasers provided information on the NGL1 form. For January 2000 forward, these six companies plus additional designated major purchasers will provide information on the NGL-100 form.

This Reporting Guide only provides reporting instructions for the NGL-100 form. Reporting instructions for the NGL1 form are contained in the "Alberta Natural Gas Royalty Principles and Procedures" manual.

Because of the importance of the data, there are penalties for late and inaccurate reporting. The Department of Resource Development will accept submissions either by mail or by fax.

The Natural Gas Royalty Regulation, 1994 and the Mines and Minerals Act are the final authorities on the reporting process and will prevail over statements made in this guide.

HOW THIS GUIDE WILL HELP YOU

This guide has been prepared to help you determine the following:

- How to complete the form using the instructions and examples provided;
- How to submit revisions to prior months' submissions;
- Key things such as reporting deadlines, late reporting penalties and minimum reporting requirements; and
- Answers to various questions.

In addition, this guide contains an explanation of the *Natural Gas Liquids Reference Prices and Allowances Calculations*, and a *Glossary of Terms*.

WHERE DO YOU SEND THE FORM?

The NGL-100 form is to be submitted to the Department of Resource Development in Calgary at the following addresses:

Hardcopy to: Alberta Resource Development
Information Services
3rd Floor, 801 – 6th Ave. S.W.
Calgary, Alberta
T2P 3W2

or

Fax to: Gas Valuation in Calgary
Fax (403) 297-5400
Telephone (403) 297-5514

- All reporting companies are permitted to submit their form via fax. If the submission is sent by fax, do not send the original form.
- Upon request, reporting companies will be provided with a diskette containing an Excel spreadsheet of the NGL-100 form.
- At this time, electronic submissions are not permitted.

REPORTING DEADLINES

REPORTING CALENDAR FOR THE NGL-100 FORM

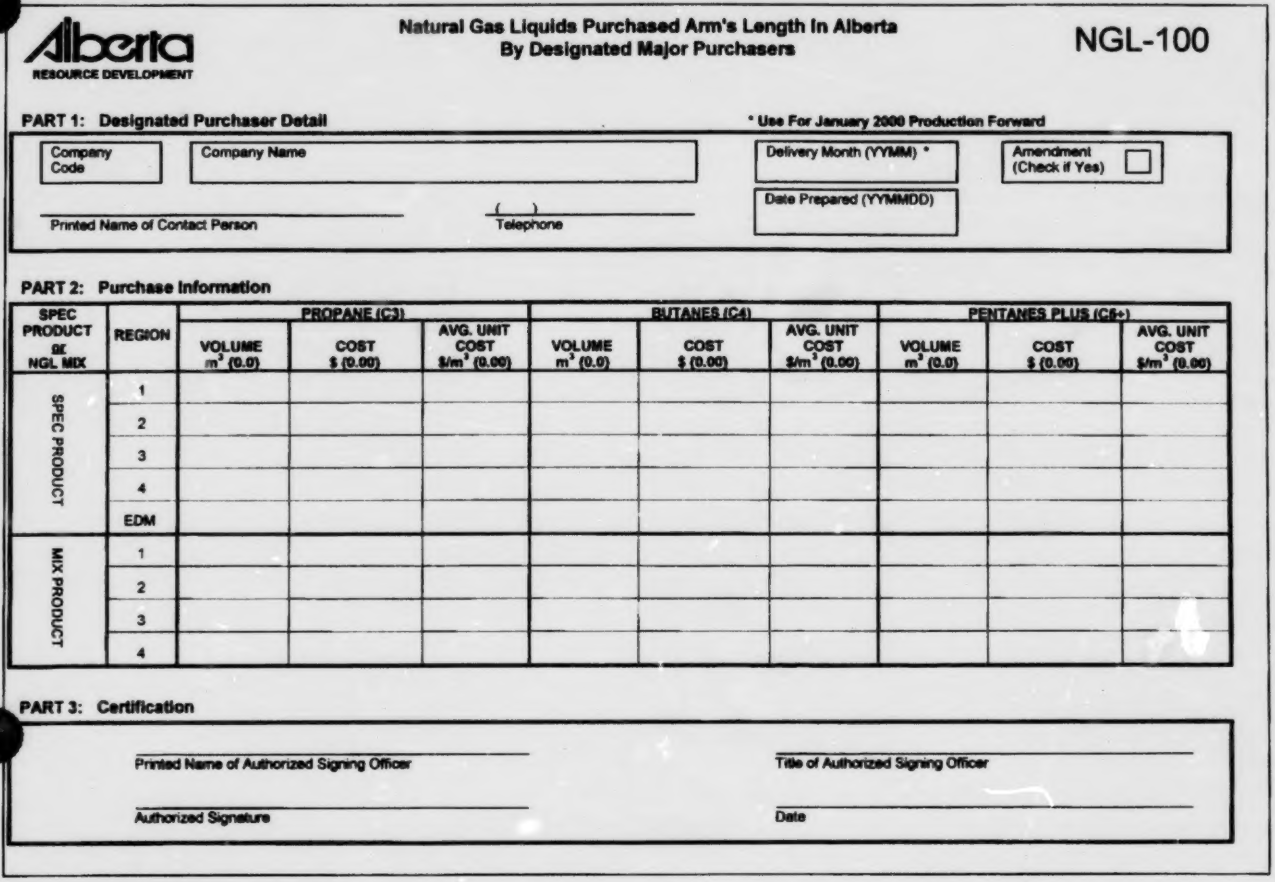
This calendar indicates the reporting deadlines for the period January 2000 through December 2001 for the NGL-100. The form must arrive at the Calgary offices of the Department of Resource Development no later than 12:00 midnight, Calgary time, on the 10th day of the second month following the production month.

If the 10th day of the month falls on a weekend or holiday and the Department of Resource Development is closed, then the form must arrive at the Calgary offices of the Department of Resource Development no later than 12:00 midnight, Calgary time, on the next business day.

REPORTING DEADLINES

DELIVERY MONTH	2000	2001
JANUARY	March 10, 2000	March 12, 2001
FEBRUARY	April 10, 2000	April 10, 2001
MARCH	May 10, 2000	May 10, 2001
APRIL	June 12, 2000	June 11, 2001
MAY	July 10, 2000	July 10, 2001
JUNE	August 10, 2000	August 10, 2001
JULY	September 11, 2000	September 10, 2001
AUGUST	October 10, 2000	October 10, 2001
SEPTEMBER	November 10, 2000	November 12, 2001
OCTOBER	December 11, 2000	December 10, 2001
NOVEMBER	January 10, 2001	January 10, 2002
DECEMBER	February 12, 2001	February 11, 2002

HOW TO COMPLETE THE NGL-100 FORM



Alberta
RESOURCE DEVELOPMENT

Natural Gas Liquids Purchased Arm's Length In Alberta
By Designated Major Purchasers

NGL-100

PART 1: Designated Purchaser Detail

* Use For January 2000 Production Forward

Company Code

Company Name

Delivery Month (YYMM) *

Amendment (Check if Yes) ☐

Date Prepared (YYMMDD)

Printed Name of Contact Person

( ) Telephone

PART 2: Purchase Information

SPEC PRODUCT or NGL MIX	REGION	PROPANE (C3)			BUTANES (C4)			PENTANES PLUS (C5+)		
		VOLUME m^3 (0.0)	COST $ (0.00)	AVG. UNIT COST $/$m^3$ (0.00)	VOLUME m^3 (0.0)	COST $ (0.00)	AVG. UNIT COST $/$m^3$ (0.00)	VOLUME m^3 (0.0)	COST $ (0.00)	AVG. UNIT COST $/$m^3$ (0.00)
SPEC PRODUCT	1									
	2									
	3									
	4									
	EDM									
MIX PRODUCT	1									
	2									
	3									
	4									

PART 3: Certification

Printed Name of Authorized Signing Officer

Title of Authorized Signing Officer

Authorized Signature

Date

REPORTING INSTRUCTIONS

Effective with the January 2000 production month, the NGL-100 form is to be reported by the designated purchasers of propane (C3), butanes (C4) and pentanes plus (C5+) in the province of Alberta. The NGL-100 filers are designated by the Minister of the Department of Resource Development and are required to report arm's length purchase information of specification (spec) and mix product at field locations and the Edmonton Area.

An arm's length purchase is defined as a transaction occurring between persons who are not related within the meaning of the Canadian Institute of Chartered Accountants (CICA) Handbook.

Transfers of products between different departments of the same company are not arm's length transactions and are not reported.

PART 1: DESIGNATED PURCHASER DETAIL

COMPANY CODE

The unique code assigned to the reporting company by the Alberta Energy and Utilities Board (AEUB). If no AEUB code exists, contact Gas Valuation and a code will be assigned.

COMPANY NAME

The name of the company reporting to the Department of Resource Development.

DELIVERY MONTH

The year and month when the NGLs were purchased and when prior months' adjustments were transacted. For example, January 2000 is reported as 0001.

HOW TO COMPLETE THE NGL-100 FORM

AMENDMENT
Refer to *Revisions to Prior Months' Submissions* in this guide.

PRINTED NAME OF CONTACT PERSON
The name of the person making this submission. Any Department of Resource Development questions regarding the submitted information will be directed to this person.

TELEPHONE
The telephone number, including the area code, of the contact person.

DATE PREPARED
The year, month and day (YYMMDD) on which the NGL-100 form is prepared. When an amendment is submitted, this date is used to determine which form for a delivery month is the most current.

PART 2: PURCHASE INFORMATION

NGL-100 filers are required to report, by region, all of their arm's length purchases of Spec Product and NGL Mix at a field location. In addition, Spec Product purchased arm's length in the Edmonton Area (EDM) at non-field locations is required to be reported. Refer to the *NGL Regions* section of this guide for a description of Regions 1 through 4 as well as a description of the Edmonton Area.

- Propane (C3), butanes (C4) and pentanes plus (C5+) that are purchased as specification product (i.e. generally after fractionation) are reported as Spec Product, in regions 1 – 4 (field) or EDM (non-field location in the Edmonton Area).
- Propane (C3), butanes (C4) and pentanes plus (C5+) that are purchased in a mix (i.e. prior to fractionation) are reported as Mix Product in regions 1 – 4 (field).
- Purchases of butanes would include purchases of iso and normal butanes.
- Spec Product or Mix Product that is purchased at a field location in the Edmonton Area is reported in region 1 under the appropriate Spec or Mix category.
- Pentanes plus also includes field condensate for NGL-100 reporting purposes.
- All information must be filed on a single NGL-100 form for a particular delivery month. For example, it is not acceptable to file C5+ purchases on one form and file C3 purchases on a second form. The NGL-100 system is designed such that a subsequent submission for the same delivery month will completely overwrite/replace the preceding submission for all entry fields.
- When reporting the purchase cost, the following fees must be added back to the purchase cost if they are deducted in the contract/invoice:
  - distribution fees;
  - marketing fees;
  - handling fees;
  - processing fees;
  - pipeline equalization charges; and
  - any other fee or charge that is not directly related to transporting the product.
- When reporting purchases of spec propane or propane in a mix, only include ethane volumes that are paid for as propane under the purchase contract. Costs relating to ethane volumes not paid for as propane (penalty volumes) should be excluded. Refer to the *Examples* section of this guide.
- Buy/Sells, Exchanges and Swaps are not arm's length transactions and must be excluded from reporting. These are cases where 1) the purchase and sale are referenced under the same contract, or 2) more than one contract exists, but these are "tied" contracts (either by references made within each contract or by a master contract). A purchase and sale with the same company would not be a Buy/Sell if they are under independent contracts. Note that a net billing on the invoice does not necessarily mean that the

transaction is a Buy/Sell, Exchange or Swap, because the net billing reflects an accounting function.

- Reporting estimated data, other than accruals, is not acceptable. You are required to report according to your business records.

VOLUME
Volume, in cubic metres (m^3) purchased in the current delivery month plus previous months' adjustments which are transacted in the current delivery month. Report to one decimal place.

COST
Cost of the product(s) purchased in the current delivery month plus previous months' adjustments which are transacted in the current delivery month. Report dollars and cents to 2 decimal places (Canadian currency before GST).

AVERAGE UNIT COST ($/m^3)
The weighted average unit cost for the month for each of propane, butanes and pentanes plus, calculated as cost divided by volume. Report dollars and cents to 2 decimal places.

PART 3: CERTIFICATION

PRINTED NAME OF AUTHORIZED SIGNING OFFICER
The printed full name of the Authorized Signing Officer whose signature appears in "Authorized Signature".

TITLE OF AUTHORIZED SIGNING OFFICER
The position title of the Authorized Signing Officer whose signature appears in "Authorized Signature".

AUTHORIZED SIGNATURE
The signature of the Authorized Signing Officer who is authorized to sign the submission on behalf of the company.

DATE
The date on which the Authorized Signing Officer signed the NGL-100 submission.

REVISIONS TO PRIOR MONTHS' SUBMISSIONS

Where revisions to a prior delivery period are required, two types of revisions have been identified and, accordingly, require two different methods of reporting.

ERRORS AND OMISSIONS (AMENDMENTS)

This type of revision results from incorrect reporting (i.e., a transcription error, or information that was overlooked by the reporting company). These errors and omissions cause the information reported by the company to be inconsistent with its business records. In these cases, an amended NGL-100 form must be completed in full and submitted as a replacement form for the original delivery month. Ensure the Amendment Box is checked when submitting an amendment.

- If you were a designated purchaser from January 1994 to December 1999, amendments from this period must be provided on the NGL1 form. For NGL1 reporting instructions, refer to the "Alberta Natural Gas Royalty Principles and Procedures" manual.

FINANCIAL/BUSINESS ADJUSTMENTS

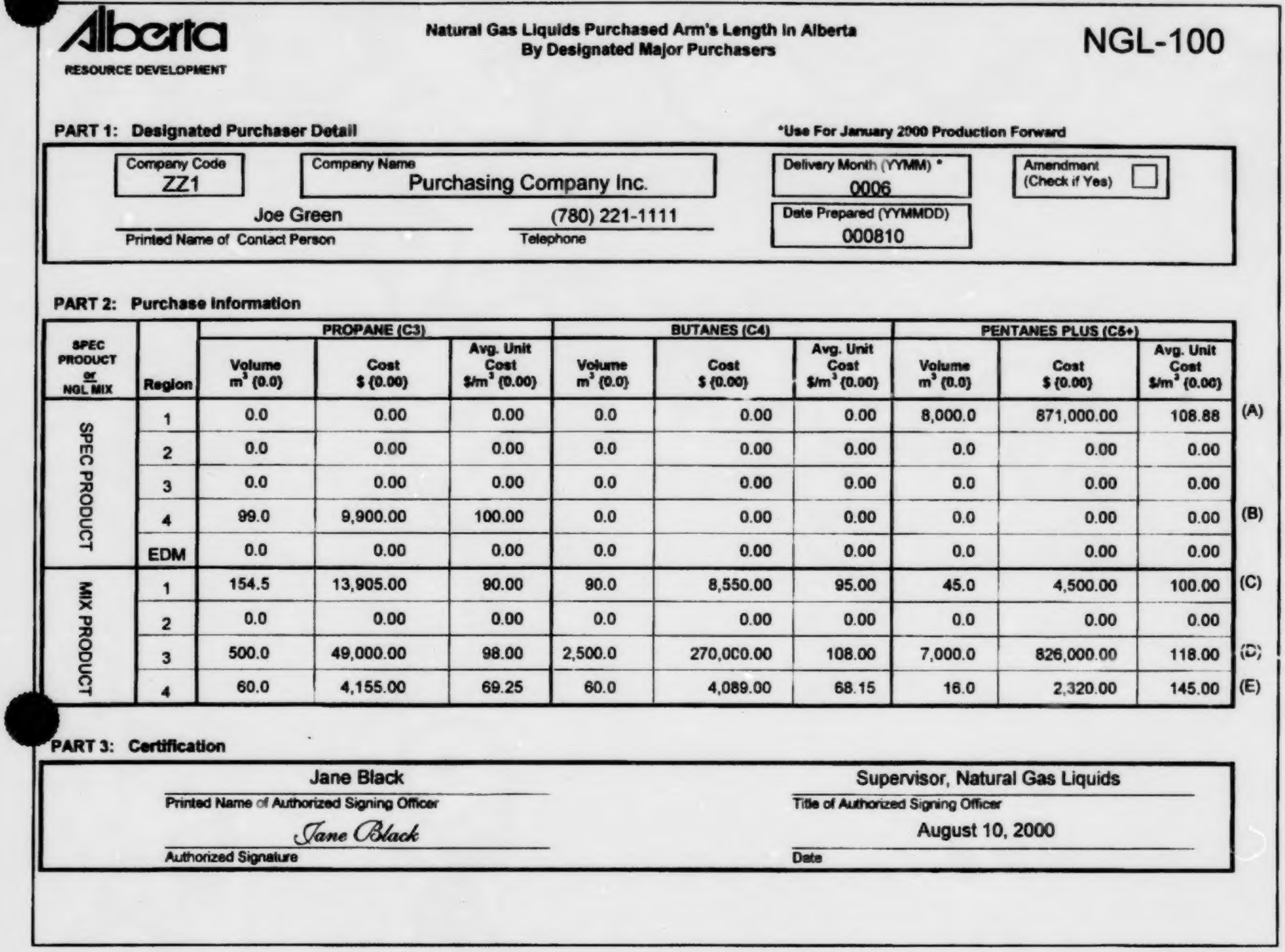
This type of revision results from a redetermination or reallocation of data by a plant operator, pipeline company, producer, shipper or customer. Such revisions, which usually require financial adjustments, are included with (rolled into) the information for the current delivery month in which these adjustments were transacted.

- A separate NGL-100 amendment for the past delivery month(s) must not be submitted.
- These adjustments are reported in the current delivery month whether or not there are purchases for the current delivery month.

HOW TO COMPLETE THE NGL-100 FORM

- Adjustments to delivery months prior to January 2000 are also included in the current delivery month.
- Do not check the Amendment Box when including a financial/business adjustment.

HOW TO COMPLETE THE NGL-100 FORM



Alberta
RESOURCE DEVELOPMENT

Natural Gas Liquids Purchased Arm's Length In Alberta
By Designated Major Purchasers

NGL-100

PART 1: Designated Purchaser Detail

*Use For January 2000 Production Forward

Company Code	ZZ1
Company Name	Purchasing Company Inc.
Delivery Month (YYMM) *	0006
Amendment (Check if Yes)	☐
Printed Name of Contact Person	Joe Green
Telephone	(780) 221-1111
Date Prepared (YYMMDD)	000810

PART 2: Purchase Information

SPEC PRODUCT or NGL MIX	Region	PROPANE (C3) Volume m³ (0.0)	PROPANE (C3) Cost $ (0.00)	PROPANE (C3) Avg. Unit Cost $/m³ (0.00)	BUTANES (C4) Volume m³ (0.0)	BUTANES (C4) Cost $ (0.00)	BUTANES (C4) Avg. Unit Cost $/m³ (0.00)	PENTANES PLUS (C5+) Volume m³ (0.0)	PENTANES PLUS (C5+) Cost $ (0.00)	PENTANES PLUS (C5+) Avg. Unit Cost $/m³ (0.00)	
SPEC PRODUCT	1	0.0	0.00	0.00	0.0	0.00	0.00	8,000.0	871,000.00	108.88	(A)
	2	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	
	3	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	
	4	99.0	9,900.00	100.00	0.0	0.00	0.00	0.0	0.00	0.00	(B)
	EDM	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	
MIX PRODUCT	1	154.5	13,905.00	90.00	90.0	8,550.00	95.00	45.0	4,500.00	100.00	(C)
	2	0.0	0.00	0.00	0.0	0.00	0.00	0.0	0.00	0.00	
	3	500.0	49,000.00	98.00	2,500.0	270,000.00	108.00	7,000.0	826,000.00	118.00	(D)
	4	60.0	4,155.00	69.25	60.0	4,089.00	68.15	16.0	2,320.00	145.00	(E)

PART 3: Certification

Printed Name of Authorized Signing Officer	Jane Black
Title of Authorized Signing Officer	Supervisor, Natural Gas Liquids
Authorized Signature	Jane Black
Date	August 10, 2000

EXAMPLES

For the business (accounting) month of July 2000 (when the June 2000 delivery month is processed)…

(A) Purchasing Company Inc. (Company Code: ZZ1) made an arm's length purchase of field condensate at a field location in Region 1 for the delivery month of June 2000.

	Volume (m³)	Cost	Avg. Unit Cost/m³
C5+	8,000.0	$896,000.00	$112.00

Due to a re-allocation of costs, Purchasing Company Inc. (PCI) also received a price adjustment to the September 1999 field condensate purchase. The adjustment was entered onto PCI's accounting records in the July 2000 business month.

September 1999 delivery month original invoice:

	Volume (m^3)	Cost	Avg. Unit Cost/m^3
C5+	5,000.0	$600,000.00	$120.00

September 1999 delivery month revised invoice:

	Volume (m^3)	Cost	Avg. Unit Cost/m^3
C5+	5,000.0	$575,000.00	$115.00

PCI was credited $25,000.00 for the September 1999 delivery month. PCI would report the following on the June 2000 NGL-100 submission.

Volume (m^3)	Cost	Avg. Unit Cost/m^3
8,000.0	$871,000.00	$108.88
	↑	
	$896,000.00	
	<$25,000.00>	
	$871,000.00	

Note that field condensate is included as spec pentanes for NGL-100 reporting purposes.

(B) Purchasing Company Inc. (PCI) has a spec propane purchase contract for 100 units at a net propane price of $100/$m^3$. The purchase contract is arm's length at a field location in Region 4. The contract contains a 2% ethane penalty.

For the June 2000 delivery month, PCI received the following:

97.0 m^3 of C3
3.0 m^3 of C2
100.0 m^3 Total

Under the ethane penalty provision of the contract, 2.0 m^3 of ethane (100.0 m^3 total x 2%) will be treated as propane and priced at the C3 price.

- Report only the volume that was paid for: 99.0 m^3 @ $100/$m^3$

↑
97.0 m^3 of C3
+2.0 m^3 of C2 treated as propane

(C) Purchasing Company Inc. (PCI) has a C3+ (C3 mix) contract for 300 units of C3+ purchased arm's length at a field location in Region 1. The contract contains a 3% ethane penalty.

For the June 2000 delivery month, PCI received the following:

Volume (m^3)		Avg. Unit Cost/m^3
5.0	CO2	$8.00
10.0	C2	$90.00*
150.0	C3	$90.00
90.0	C4	$95.00
45.0	C5+	$100.00
300.0	Total	

* Allowable ethane portion = 150.0 m^3 of C3 x 3% = 4.5 m^3 of ethane that will be treated as propane and invoiced at the propane price.
Total C3 to be reported = 150.0 + 4.5 = 154.5 m^3

		Volume (m^3)	Cost	Avg. Unit Cost/m^3
Report:	C3	154.5 *	$13,905.00	$90.00
	C4	90.0	$8,550.00	$95.00
	C5+	45.0	$4,500.00	$100.00
		289.5 Total		

(D) Purchasing Company Inc. made an arm's length purchase of Mix Product (10,000.0 m^3) at a field location in Region 3. The mix contained the following products which were priced according to the terms of the contract. The contract included deductions for fractionation and transportation.

	Gross Price/m^3	Frac. /m^3	Transp. /m^3	Volume (m^3)	Cost	Avg. Unit Cost/m^3
C3	$120.00	$12.00	$10.00	500.0	$49,000.00	$98.00
C4	$130.00	$12.00	$10.00	2,500.0	$270,000.00	$108.00
C5+	$140.00	$12.00	$10.00	7,000.0	$826,000.00	$118.00
				10,000.0		

No other deductions were shown on the invoice.

- ◆ The volumes, costs and average unit costs are entered on the NGL-100 form.

(E) Purchasing Company Inc. made an arm's length purchase of 136.0 m^3 of Mix Product at a field location in Region 4. The mix contained the following products which were priced according to the terms of the contract (respective prices after deductions).

	Volume (m^3)	Avg. Unit Cost /m^3
C3	60.0	$66.00
C4	60.0	$65.00
C5+	16.0	$145.00
	136.0	

Deductions included $11.23/m^3 for fractionation, $3.25/m^3 for propane marketing and $3.15/m^3 for butanes marketing.

	Avg. Unit Cost/m^3	Add back deductions not allowed: Mktg/m^3	Volume (m^3)	Cost	Recalculated Avg. Unit Cost/m^3
C3	$66.00	$3.25	60.0	$4,155.00	$69.25
C4	$65.00	$3.15	60.0	$4,089.00	$68.15
C5+	$145.00	$0.00	16.0	$2,320.00	$145.00
			136.0 Total		

- As marketing costs are not an allowable deduction, they are added back to the average unit cost for each product.
- Fractionation is an allowable deduction to arrive at an average unit cost for Mix Products at a field location.

(F) Purchasing Company Inc. purchased 1,000.0 m^3 under a spec propane purchase contract from ABC Company Inc. for a total cost of $60,000.00. PCI is a wholly owned subsidiary of ABC Company Inc.

- No reporting is required as the above parties are related and the transaction is not arm's length.

(G) Purchasing Company Inc. purchased 1,000.0 m^3 of spec propane from DEX Ltd. at a field location in Region 3 and agreed to resell 1000.0 m^3 of spec propane to DEX Ltd. in the Edmonton Area.

- As this is a Buy/Sell arrangement, no reporting is required. An example of a Buy/Sell arrangement is where:
  1) The purchase and sale are referenced under the same contract, or
  2) More than one contract exists, but these are "tied" contracts (either by reference made within each contract or by a master contract).
- If the purchase and sale were not tied/connected to each other, then the purchase would be reported.

HOW TO COMPLETE THE NGL-100 FORM

QUESTIONS AND ANSWERS

1. **How do you report multiple arm's length purchases of propane, butanes, and pentanes plus, involving several custody transfers at the same field location?**

   Each designated purchaser will report its arm's length field purchase transactions at a field location which is normally at the inlet or outlet of a gas processing plant or field straddle plant. No tracking of where these products came from or where they are going is required.

2. **Am I still required to report on the NGL-100 form if there were no arm's length purchases of propane, butanes, or pentanes plus during the month?**

   Yes, a zero data NGL-100 form must be completed, with zeros in all the blank fields. The zero data NGL-100 form must be submitted by the reporting deadline to avoid late reporting penalties. If you are no longer engaged in the business of purchasing propane, butanes or pentanes plus, then notify Gas Valuation and your reporting requirement will be reviewed.

3. **Do you still need to submit amendments to the NGL1 form after December 1999?**

   Yes, for the six designated NGL1 reporting companies. If you discover an error/omission for a delivery month where an NGL1 form was used, you are required to submit an NGL1 amendment.

[illegible]. **How do I handle financial/business adjustments to months prior to January 2000?**

These adjustments must be rolled into the current month's NGL-100 form submission.

5. **What is the difference between Spec Product and Mix Product?**

   Spec Product(s) is the resulting component(s) after fractionation. Mix Product is an NGL stream which has not been fractionated into its individual components.

6. **What is a field purchase?**

   For NGL-100 reporting purposes, a field purchase occurs at a field location which is normally the entry or exit of a gas processing plant or field straddle plant. An NGL product stream may end up getting reported more than once [i.e. Mix Product is purchased at the exit of a gas plant *(reported on the NGL-100 form by a designated purchaser)*, the same mix stream is transported to a field straddle plant where it's resulting products are sold to another designated purchaser. These products, if purchased arm's length, must also be reported on the NGL-100 form by the second designated purchaser]. Refer to *Glossary*.

7. **Are straddle plant purchases reported?**

   Report field straddle plant purchases. Do not report mainline straddle plant purchases.

[illegible]. **If I purchase Spec Product or Mix Product arm's length at a gas processing plant in the Edmonton Area, do I have to report?**

Yes. Report this information under Region 1 as it is a field purchase.

HOW TO COMPLETE THE NGL-100 FORM

9. Why are transportation differentials not reported on the NGL-100 form?

The DRD will be calculating the transportation differentials from the information that is submitted on the NGL-100 form.

10. Do I report NGL purchases at a pipeline interconnect?

No, not normally. Pipeline interconnects are not normally field locations. However, if there is a gas processing plant or field straddle plant at the pipeline interconnect and the purchase was made at either the inlet or outlet of the plant, then the purchase is to be reported on the NGL-100 form.

11. What if I am purchasing NGLs at a point downstream of a gas plant and the seller is paying the transportation charges, should I report this purchase?

No. Do not report this purchase as it did not occur at a field location.

12. If I purchase Mix Product at a field location and the contract does not include charges for transportation or fractionation, do I deduct those charges from my purchase price when they are incurred?

No. Just report the prices of the products purchased at the field location.

13. Is Caroline Condensate in Region 2 to be reported any differently than any other field purchase of pentanes plus?

No.

14. Are purchases at a storage facility to be reported?

Yes, if the storage facility is at a field location. Spec NGL purchases must also be reported at non-field storage facilities located in the Edmonton Area.

15. If our subsidiary, a separate legal entity, is a designated NGL-100 purchaser, is our company required to report our NGL-100 purchases also?

No, only the designated major purchaser (a separate legal entity) is required to report its arm's length purchases.

16. Company B has been reporting large volumes of Spec C5+ for the past year. In the current production month they begin purchasing spec propane and spec butanes. The arm's length purchase volumes are 30.0 m^3 of propane and 20.0 m^3 of butanes and they expect that these small amounts will be purchased every second month throughout the year. Should Company B report the C3 and C4?

Yes. Company B has been designated by the Minister to report on the NGL-100 form all arm's length purchases of propane, butanes and pentanes plus, regardless of how small the volumes are.

HOW TO COMPLETE THE NGL-100 FORM

ADMINISTRATIVE POINTS

IF YOU NEED HELP

If you have questions when preparing the NGL-100 form, you may contact Gas Valuation at this address:

Alberta Resource Development
Gas Valuation
3rd Floor, 801 – 6th Ave. S.W.
Calgary, Alberta
T2P 3W2

Telephone (403) 297-5514
Fax (403) 297-5400

For explanations of terms used in this guide and on the form refer to the *Glossary of Terms*.

LATE REPORTING PENALTIES

To ensure timely reporting, a late reporting penalty of $1,000 is assessed for each month or part of a month that a company fails to provide an NGL-100 form. A form is considered late if it is not received by the reporting deadline (refer to reporting calendar) or if it does not meet the minimum reporting requirements by the reporting deadline.

Legislative authority to assess penalties for NGL-100 forms resides in the Mines and Minerals Act and the Natural Gas Royalty Regulation, 1994 *(the Act, the Regulation)*.

MINIMUM REPORTING REQUIREMENTS

An NGL-100 form must:

- be in a form prescribed or approved by the Department of Resource Development. A form is acceptable if it is an original, photocopy or facsimile of a Department of Resource Development printed form.
- be legible and permanent; pencil is not acceptable.
- be signed or validated by or on behalf of the person furnishing the form. A person is defined as the legal entity required to report.
- sufficiently identify the person furnishing the report.

THINGS TO NOTE BEFORE SENDING SUBMISSIONS

- Reporting zeros in all blank fields is required.
- Report volume in m^3 to one decimal point.
- Report cost to the nearest cent.
- Report average unit cost in dollars per cubic metre to the nearest cent.
- If your submission involves a complex or unusual situation, contact Gas Valuation. Please do not write comments on the form; most particularly, do not write across the spaces in which entries are made.
- All reporting companies are permitted to submit their form via fax. If the submission is sent by fax, do not send the original form.

GOODS AND SERVICES TAX (GST)

The GST must not be included in any cost submitted on the NGL-100 form.

HOW TO COMPLETE THE NGL-100 FORM

KEEPING RECORDS

You must keep records used for the purpose of preparing the NGL-100 form for 6 years following the end of the year to which the production month applies. Refer to Section 46 of the Mines and Minerals Act.

AUDIT

The Department of Resource Development has the authority to audit a company's business records for the purpose of ensuring the accuracy of submitted data. Refer to Section 46 of the Mines and Minerals Act.

CONFIDENTIALITY OF DATA

Confidentiality will be rigorously maintained in the handling of the data you submit and in respect to the manner in which it is used by the Department of Resource Development. Refer to Section 49 of the Mines and Minerals Act.

OTHER PENALTIES

A person who fails to keep required records, or who knowingly submits a report that is false or misleading, is guilty of an offence and subject to penalties pursuant to section 59 of the Mines and Minerals Act.

DESCRIPTION OF THE NATURAL GAS LIQUIDS REFERENCE PRICES AND ALLOWANCES CALCULATIONS

BACKGROUND

A joint industry-government review, completed in 1998, of the Natural Gas Liquids (NGLs) reference prices and allowances for calculation of royalty resulted in recommendations for changes that will increase the accuracy of the system by providing more representative average plant gate (field) prices, while maintaining a relatively simple reporting system.

NGL reference prices and allowances are determined by the Minister each month for the purpose of valuing the Crown's royalty share of NGLs. The past model (NGL1 form), used to determine the prices for propane and butanes, was based on purchases reported by six large volume purchasers. They reported purchases based on an Edmonton price as well as the associated transportation differentials to move product from the field to Edmonton. The pentanes plus price model was based on pentanes plus and light crude oil prices posted by Edmonton refiners. Crude oil postings were used, based on the historical close price correlation with pentanes plus, and the small number of pentanes plus postings.

Three main concerns with the past model were identified:

1. Over a period of time, the pentanes plus reference price departed significantly from actual Edmonton market prices for pentanes plus.
2. The reliance on Edmonton based transactions limited the purchases that were reported, because an increasing number of sales transactions were occurring at non-Edmonton based prices.
3. The arm's length purchase volumes that were used represented a small percentage of total provincial Crown production, which could lead to some risk of the prices not being sufficiently representative of the actual value of the resource.

The NGL review committee recommended that a replacement field price model be introduced that does not depend solely on Edmonton based transactions. The new model addresses the identified concerns by:

1. Using arm's length purchase transactions at field locations and in the Edmonton Area to determine the net Propane, net Butanes and net Pentanes Plus Reference Prices, whether or not the transactions are at Edmonton based prices.
2. Adding additional NGL designated purchasers to increase transactions used in establishing the reference prices and the transportation allowances.

REPORTED INFORMATION

Each month, commencing with January 2000 production, designated purchasers of NGLs will report their summarized arm's length volumes, costs and purchase prices on the NGL-100 form. Field volumes, costs and purchase prices are reported for propane, butanes and pentanes plus: separately for spec and mix; and categorized into the existing four provincial transportation regions. Non-field purchases of spec production in the Edmonton Area (same area as under past rules) are also reported. All current business rules that define a valid arm's length transaction and ineligible fees will continue to apply.

CALCULATIONS

Following this section is a diagram of the calculation.

The Department of Resource Development will perform the following calculations:

1. Calculate weighted average prices for each of the 27 categories (3 reference prices and 24 field prices).

GENERAL INFORMATION

2. The weighted average purchase prices for spec propane, butanes and pentanes plus, at non-field locations in the Edmonton Area will be published as the reference prices.

3. Calculate transportation differentials for each product in regions 1 to 4, by subtracting average field prices from the reference prices.

4. Calculate a weighted average spec differential in each region by combining propane and butanes spec differentials in that respective region. The average spec differential for each region will be published as the monthly spec product transportation allowance.

5. Calculate a weighted average mix differential in each region by combining propane, butanes and pentanes plus, mix differentials. Subtract the published fractionation allowance ($7.00/m^3 for 1999) from each region's weighted average mix differential. The weighted average mix differential in each region will be published as the monthly NGL mix transportation allowance.

6. The weighted average spec differential for pentanes plus (calculated in step 3 above) for each region will be published as the monthly spec pentanes plus transportation allowance.

7. If in any month, there is no information available to publish a Spec Product or Mix Product transportation allowance for a region, the transportation allowance will be calculated as the weighted average of the other regions for the same Spec Product or Mix Product transportation allowance. The weightings will be based on the previous year's production (past business rules specify a simple average).

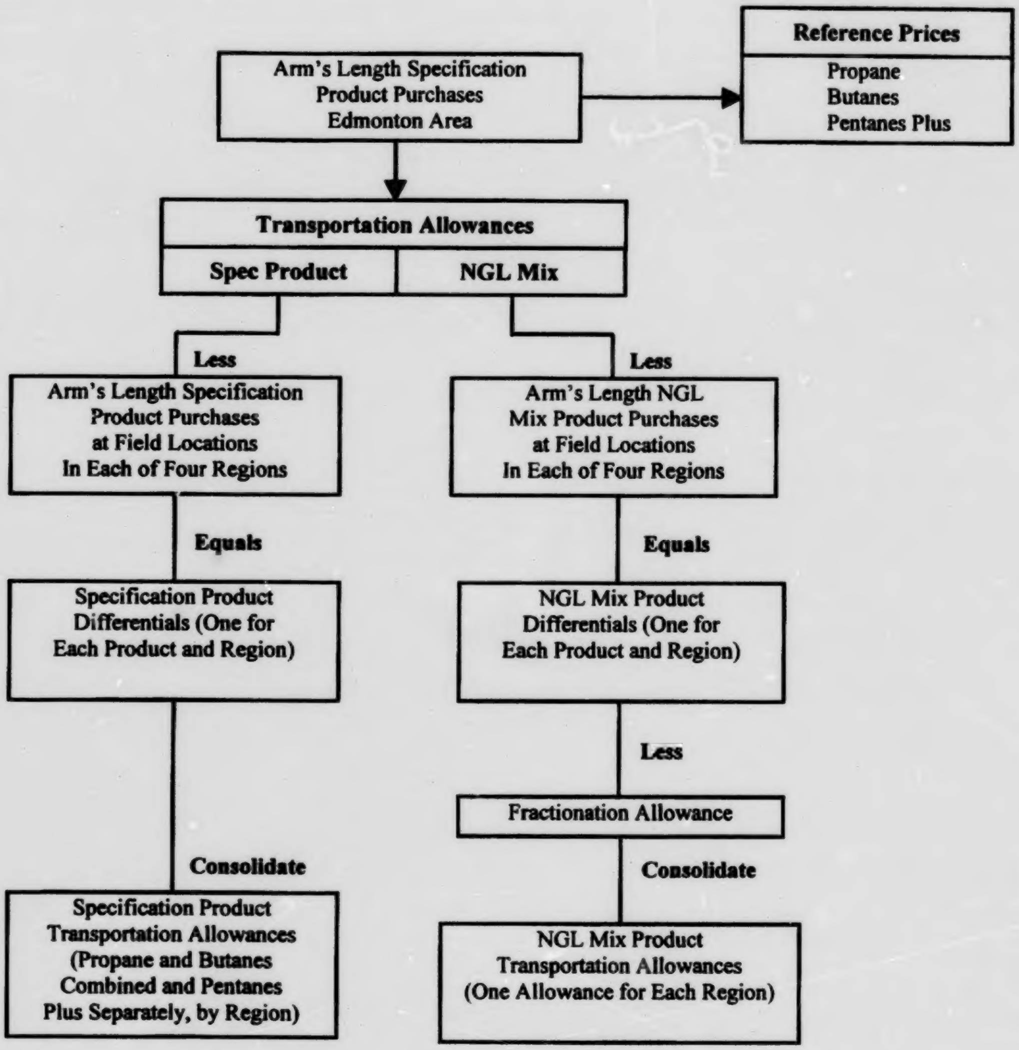
8. If in any month there is no information available to publish the spec pentanes plus transportation allowance for a region, or if the information has been submitted by a single reporting company, the spec pentanes plus transportation allowance will be calculated as the simple average of the preceding twelve months for that region. A continuing situation of two months or more will require a revisit of the business rules.

9. The past business rules for including prior period amendments will continue under the new model. The limit on the effect of prior period amendments to the reference prices will remain at 10%. There will continue to be a limit of 100% of the simple average of applicable product reference prices, on the effect that prior period amendments can have on published transportation allowances.

10. The past business rules for fractionation allowance and floor prices will continue.

11. Under the new model, a total of 3 reference prices and 13 allowances (including fractionation) will be published, as with the past model.

NGL REFERENCE PRICES AND ALLOWANCES CALCULATIONS FOR PROPANE, BUTANES AND PENTANES PLUS


Arm's Length Specification
Product Purchases
Edmonton Area
Reference Prices
Propane
Butanes
Pentanes Plus
Transportation Allowances
Spec Product
NGL Mix
Less
Arm's Length Specification
Product Purchases
at Field Locations
In Each of Four Regions
Less
Arm's Length NGL
Mix Product Purchases
at Field Locations
In Each of Four Regions
Equals
Specification Product
Differentials (One for
Each Product and Region)
Equals
NGL Mix Product
Differentials (One for
Each Product and Region)
Less
Fractionation Allowance
Consolidate
Specification Product
Transportation Allowances
(Propane and Butanes
Combined and Pentanes
Plus Separately, by Region)
Consolidate
NGL Mix Product
Transportation Allowances
(One Allowance for Each Region)

Alberta
RESOURCE DEVELOPMENT

Natural Gas Liquids Purchased Arm's Length In Alberta
By Designated Major Purchasers

NGL-100

PART 1: Designated Purchaser Detail

* Use for January 2000 Production Forward

Company Code

Company Name

Delivery Month (YYMM)*

Amendment (Check if Yes) ☐

Date Prepared (YYMMDD)

Printed Name of Contact Person

(   )
Telephone

PART 2: Purchase Information

SPEC PRODUCT or NGL MIX	Region	PROPANE (C3)			BUTANES (C4)			PENTANES PLUS (C5+)		
		Volume m^3 {0.0}	Cost \$ {0.00}	Avg. Unit Cost \$/m^3 {0.00}	Volume m^3 {0.0}	Cost \$ {0.00}	Avg. Unit Cost \$/m^3 {0.00}	Volume m^3 {0.0}	Cost \$ {0.00}	Avg. Unit Cost \$/m^3 {0.00}
SPEC PRODUCT	1									
	2									
	3									
	4									
	EDM									
MIX PRODUCT	1									
	2									
	3									
	4									

PART 3: Certification

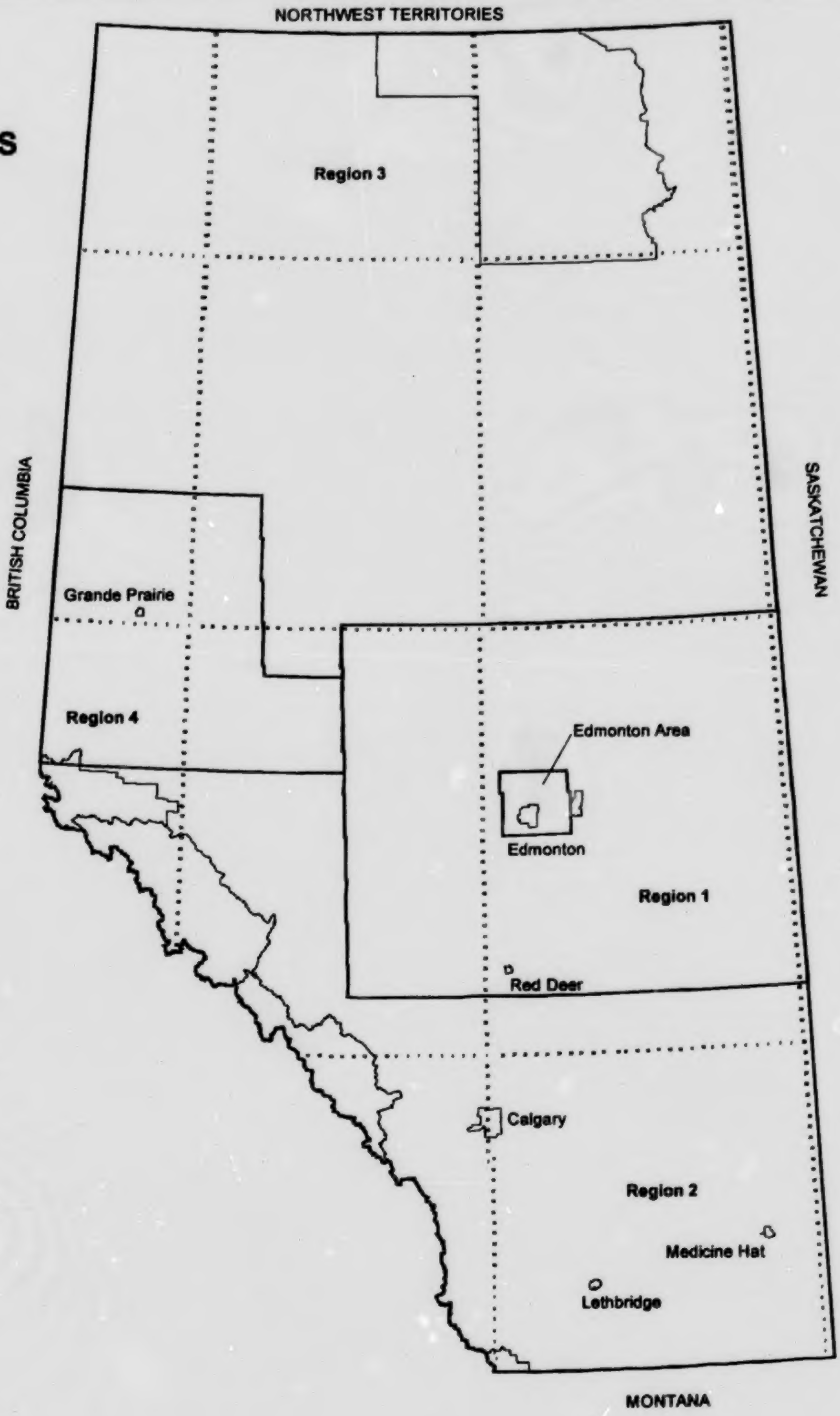
Printed Name of Authorized Signing Officer

Title of Authorized Signing Officer

Authorized Signature

Date

NGL REGIONS


NORTHWEST TERRITORIES
Region 3
BRITISH COLUMBIA
SASKATCHEWAN
Grande Prairie
Region 4
Edmonton Area
Edmonton
Region 1
Red Deer
Calgary
Region 2
Medicine Hat
Lethbridge
MONTANA

GENERAL INFORMATION

NGL REGIONS

For the purpose of reporting NGL field purchases by region on the NGL-100 form, the geographical descriptions of regions 1 – 4 and the Edmonton Area are outlined below and are depicted on the map provided.

REGION 1 is defined as the area:

- bounded on the NORTH by the 70th township line;
- bounded on the EAST by the 4th meridian;
- bounded on the SOUTH by the 35th township line;
- bounded on the WEST by the 13th range line west of the 5th meridian.

REGION 2 is defined as the area:

- bounded on the NORTH by:
    - the 35th township line, from the 4th meridian to the 13th range line west of the 5th meridian, *and*
    - the 56th township line from the 13th range line west of the 5th meridian to the Alberta-British Columbia border;
- bounded on the EAST by:
    - the 4th meridian, from the 49th parallel to the 35th township line, *and*
    - the 13th range line west of the 5th meridian, from the 35th township line to the 56th township line;
- bounded on the SOUTH by the 49th parallel;
- bounded on the WEST by the Alberta-British Columbia border.

REGION 3 is defined as the area:

- bounded on the NORTH by the 126th township line;
- bounded on the EAST by:
    - the 4th meridian, from the 70th township line north, *and*
    - the 13th range line west of the 5th meridian, from the 65th township line to the 70th township line;
- bounded on the SOUTH by:
    - the 70th township line, from the 4th meridian to the 13th range line west of the 5th meridian, *and*
    - the 65th township line, from the 13th range line west of the 5th meridian to the 20th range line west of the 5th meridian, *and*
    - the 82nd township line, from the 20th range line west of the 5th meridian to the Alberta-British Columbia border;
- bounded on the WEST by:
    - the 20th range line west of the 5th meridian, from the 65th township line to the 82nd township line, *and*
    - by the Alberta-British Columbia border from the 82nd township line north.

REGION 4 is defined as the area:

- bounded on the NORTH by:
    - the 65th township line, from the 13th range line west of the 5th meridian to the 20th range line west of the 5th meridian, *and*
    - the 82nd township line, from the 20th range line west of the 5th meridian to the Alberta-British Columbia border;
- bounded on the EAST by:
    - the 13th range line west of the 5th meridian, from the 56th township line to the 65th township line, *and*
    - the 20th range line west of the 5th meridian, from the 65th township line to the 82nd township line;
- bounded on the SOUTH by the 56th township line;
- bounded on the WEST by the Alberta-British Columbia border.

EDMONTON AREA (EDM)

The Edmonton Area (including Fort Saskatchewan) is specifically described as the area falling within:

- The Northern Boundary of Township 56;
- The Southern Boundary of Township 51;
- The Eastern Boundary of Range 21;
- The Western Boundary of Range 26;
- All West of the 4th Meridian.

GLOSSARY OF TERMS

The following terms and definitions have been prepared to assist with the terminology used in the context of this guide.

ACT

Refers to the Mines and Minerals Act.

AMENDMENTS

Refer to *Revisions to Prior Months' Submissions* in this guide.

ARM'S LENGTH

Persons shall be regarded as not dealing at arm's length with each other if, at a material time under the Regulation, they are related parties within the meaning of the CICA Handbook published from time to time by the Canadian Institute of Chartered Accountants.

BUTANES (C4)

Commercial butanes are a mixture of gaseous paraffins, normal-butane and iso-butane obtained by processing natural gas as produced and from a process in petroleum refining. It is delivered in a liquefied form and used as fuel in a gaseous form. End uses include improving volatility and octane number in gasoline, and for cooking and domestic heating.

BUY/SELL

A contract or arrangement under which a person purchases and resells NGLs to the same party. These situations usually occur as a way of transporting the product where the purchaser has priority space on the pipeline.

DEPARTMENT

The Department of Resource Development.

DESIGNATED PURCHASER

A person designated by the Minister as a major purchaser in Alberta of propane, butanes, or pentanes plus.

DILUENT

A neutral fluid added to another fluid to reduce the concentration of the second fluid in a mixture i.e. pentanes plus are used as a diluent for heavy oil.

EDMONTON AREA

The designated area around Edmonton including Fort Saskatchewan (refer to *NGL Regions*).

EPSTA FEE

The standard fee specified in the Ethane Plus System Trading Agreement for the fractionation of natural gas liquids.

ETHANE (C2)

A colorless hydrocarbon gas normally used as a raw material in the production of chemicals and plastics and as a solvent in enhanced oil recovery processes.

EXCHANGE

A transaction where the parties exchange a quantity of gas or a gas product at one location for a quantity of gas or a gas product at another location *(also called Swap).*

FIELD LOCATION

A district or area from which natural gas, gas products or field condensate are produced. These are normally gas processing plants, field straddle plants or other field facilities which process these product streams to some degree.

FIELD PURCHASE

For NGL-100 reporting purposes, an arm's length purchase of specification propane, butanes or pentanes plus, or any of these products in a mix, purchased at a *Field Location.* Field purchases can be made at either the inlet or outlet of a facility at a field location.

GLOSSARY OF TERMS

FRACTIONATION ALLOWANCE
The allowance prescribed annually which is deducted from the applicable monthly reference price to recognize the costs of fractionation of the Crown's share of a natural gas liquid mix in order to obtain the constituent products: propane, butanes and pentanes plus.

FRACTIONATION FACILITY
A facility where NGL mix is separated into specification ethane, propane, butanes and/or pentanes plus.

MAINLINE STRADDLE PLANT
Mainline straddle plants are those plants that have been designated as such by the Minister. Purchases at mainline straddle plants are not reported on the NGL-100 form.

MIX PRODUCT
In relation to natural gas liquids, is a commingled stream that may contain propane, butanes or pentanes plus together as a mix.

NATURAL GAS LIQUIDS (NGLs)
Propane, butanes and pentanes plus or any one of them.

PENTANES PLUS (C5+)
A mixture of hydrocarbons consisting wholly or mainly of pentanes plus and heavier hydrocarbons and obtained from natural gas by processing or otherwise, and also includes field condensate for NGL-100 reporting.

PRODUCTION MONTH
In relation to any natural gas, gas products or field condensate, is the month in which it is recovered or obtained.

PROPANE (C3)
A hydrocarbon gas useful for heating and metal cutting flame welding purposes. It can be stored under pressure as a liquid at atmospheric pressures, but is more volatile than butane, and high pressure is required to keep it in a liquid form.

REFERENCE PRICE
The gross price established by the Department for valuing the Crown's royalty share of propane, butanes and pentanes plus, or any one of them. The Reference Price is reduced to reflect the condition of the product (less fractionation allowance for mix), and the location of the point at which royalty is triggered (less transportation allowance).

REGULATION
The *Natural Gas Royalty Regulation, 1994* (Alberta Regulation 351/93 as amended).

SPECIFICATION PRODUCT (SPEC PRODUCT)
In relation to natural gas liquids, are propane, butanes or pentanes plus that have been processed (fractionated) to a condition where they meet purchaser specifications for product quality.

STRADDLE PLANT
A gas processing facility constructed downstream of an existing field gas plant in order to increase the NGL/ethane recovery efficiency. Field straddle plants are at *Field Locations* for NGL-100 reporting purposes.

TRANSPORTATION ALLOWANCE
The deduction from the Propane, Butanes and Pentanes Plus Reference Prices to recognize the cost of transportation associated with those products.

TRANSPORTATION REGION
In relation to Transportation Allowances, is one of the four geographic transportation regions established for the purpose of calculating representative *Transportation Allowances*.

INFORMATION LETTERS/BULLETINS

1. Introduction

Volumetric reconciliation is performed by the Alberta Department of Resource Development (the Department) to ensure that mineral quantities that have potential impact on royalty calculations are accurately reported for each production period. Three separate reconciliation processes are performed. The first is the EUB to OAS reconciliation, which compares Owner Activity Statement (OAS) data to EUB volumetric data. The other two reconciliations, the OAS Cascade and the Purchase to Sale reconciliations, compare OAS reported data only.

Sections 3, 4, and 5 describe the three reconciliation processes in detail.

2. Definitions

1999/4999 - Refers to out-of-province destinations reported on EUB reports.

9996 - An EUB code used in S **reporting***, which identifies volumes delivered to a battery for fuel.

9997 - An EUB code used in S reporting, which identifies volumes delivered for **gas lift*** recycling.

9998 - An EUB code used in S-reporting, which identifies volumes used for consumer, residential, commercial, or industrial use.

Consumer, recycling, battery/facility - This includes volumes consumed as fuel (see *Section 5.2*) and volumes to code 9998.

Lease Fuel - This can include royalty waived fuel or royalty payable fuel (see *Section 5.2*).

Location - The location on the OAS refers to the number or code of a facility where an activity occurred. When reconciling volumes from an OAS, the reconciliation is tied to the facility referred to in the location.

Net Quantities - This is the owner's share of a volume or mass reported at a Stream ID. Reconciliation uses net quantities reported on the OAS for each product owner.

Royalty Network - The royalty network (as described Appendix B, Royalty Triggers and OAS Reporting Rules for Royalty Assessment) is a collection of interconnected processing and gathering facilities that receive products either directly or indirectly from reservoirs. The network (for the Department royalty purpose) is deemed to end when the product is delivered to:

- commercial transportation facilities such as pipelines, railcars, and trucks (except in the case where a processed gas stream is transferred to a pipeline for the purpose of being eventually used as eligible fuel);
- field straddle plants (except the case of unprocessed product where the network is deemed to end at the field straddle plant outlet gate whether or not any processing of the product occurs);
- mainline straddle plants;
- fractionation plants;
- facilities for the purpose of injection;

For definition, please see Appendix N – Glossary

- facilities outside Alberta (except non-Alberta facilities on the Departm approval list); and
- refineries, terminals, treating plants.

The term Royalty Network, as defined above, is intended to be used within the context of royalty assessment and volumetric reconciliation by the Department.

3. EUB to OAS Reconciliation Details (S to OAS Document Reconciliation)

The EUB to OAS reconciliation is performed for gathering systems, gas processing plants, field straddle plants and injection facilities. There is no volumetric reconciliation of Mainline Straddle Plants, Fractionation Plants or Batteries.

The EUB S8, S20 and S21 volumetric data, at a facility level, is compared to the OAS activities reported by the facility operator for that facility. For each reconciliation product at the facility, the sum of the OAS volumes allocated to each owner will be compared to the production reported to EUB. If the sum of the OAS reported production is less than the production reported to EUB, the Operator of the facility will be provisionally assessed for the difference.

(Please refer to Section 10 and Section 26 - Enforcing Compliance with Legislation).

In the case of injection volumes potentially qualifying for royalty (injection) credit, the sum of OAS reported injection receipts will be compared to the injection receipts reported to EUB (S18). If the sum of the OAS reported injection receipts is greater than the EUB injection receipt volume, the Operator of the injection facility will be provisionally assessed for the difference.

3.1 EUB to OAS Gathering System Reconciliation (S8 to OAS)

The EUB to OAS reconciliation of "Gas" volumes for gathering systems is limited to royalty network leakage (i.e., gas dispositions that are considered to be out of the royalty network). EUB "S" volumes used in this reconciliation are S8 gas disposition volumes, which are net of system use and are considered to be dispositions out of the royalty network.

OAS volumes participating in this reconciliation are "Transfer" or "Sale" volumes referencing destinations on the OAS that are considered to be out of the royalty network.

NOTE: A "SALE" WITH A BLANK DESTINATION IS CONSIDERED TO BE OUT OF THE ROYALTY NETWORK.

The reconciliation can be summarized by the following equations:

Reconciliation Facility: Gathering System Reconciliation Product: Gas

S8: Prorated Gas sales which are out-of-royalty network (exclude recycling, battery/facility sales which are not of Code 9998)

...plus...

Prorated Gas deliveries to out-of-royalty network destinations (including injection facilities, mainline straddle plants, ex-Alberta location facilities but excluding codes 9996/9997)

...equals...

OAS: "Transfer" volumes for Gas with an out-of-network destination*

...plus...

"Sale" volumes for Gas with an out-of-network destination*

- *Alberta location - injection facilities, mainline straddle plants, transportation facilities (e.g., commercial pipelines),refineries, terminals, treating plants, or any ex-Alberta location facility.*

NOTE 1: S8 GAS DISPOSITIONS ARE ASSUMED TO BE ALL UNPROCESSED GAS; THEREFORE, DISPOSITIONS TO FIELD STRADDLE PLANTS ARE CONSIDERED TO BE DISPOSITIONS WITHIN THE ROYALTY NETWORK AND ARE EXCLUDED FROM THE "S" RECONCILIATION VOLUMES.

NOTE 2: A WORKING ASSUMPTION HAS BEEN MADE THAT THERE WOULD BE NO "PROCESS" VOLUMES REPORTED FOR GAS AT GATHERING SYSTEMS. GAS DISPOSITIONS ON THE S8 ARE EXPECTED TO BE REPORTED AS EITHER A "SALE" OR "TRANSFER" ACTIVITY ON THE OAS.

NOTE 3: CONSUMER, RECYCLING, BATTERY/FACILITY DISPOSITIONS (EXCLUDING 9998) MAY OR MAY NOT BE SUBJECT TO ROYALTY (E.G., LEASE FUEL ELIGIBLE FOR ROYALTY WAIVER, *REFER TO SECTION 5.2*). IN CASES WHERE ROYALTY IS DUE ON SOME OR ALL OF THESE VOLUMES, THE FACILITY OPERATOR MUST REPORT THESE VOLUMES ON THE OAS. THESE VOLUMES WILL APPEAR AS A CROWN FAVOUR DISCREPANCY SINCE THE OAS VOLUMES WILL BE INCLUDED BUT NOT THE CORRESPONDING S8 VOLUMES. NO ACTION IS REQUIRED ON THIS PARTICULAR CROWN FAVOR DISCREPANCY.

GAS VOLUMES SUBJECT TO EUB/OAS GATHERING SYSTEM RECONCILIATION

Recon facility type	Recon Product	Facility Activity (S) Volumes	OAS Volumes			
			Stream ID	**Str. Category**	**Activity**	**Destination**
GS	Gas	- S8 Pro-rated Sales-Consumer, Recycling, Battery/Facility: code 9998 volumes only - S8 Pro-rated Sales-Transporters Ex-province: all codes/volumes - S8 Pro-rated Sales-Distributor: all codes/volumes - S8 Pro-rated Deliveries-Mainline Straddle Plant codes/volumes, codes 1999/4999 volumes, injection facility codes (exclude codes 9996/9997)/volumes	all valid stream ID types for reported stream category*	by-product,cascade gas, production, purchase, storage	Sale**	type = IF, PL, TF, RR, TR, TM, TP, or mainline straddle
			all valid stream ID types for reported stream category*	By-product, cascade, gas, production, purchase, storage	Transfer**	type = IF, PL, TF, RR, TR, TM, TP, or mainline straddle

* *If reported stream category is GAS, only stream IDs that are sourced back to type WI, WG, UN, or IS will be included in the reconciliation.*

** *Only sale and transfer activities where there is no corresponding (i.e., same owner, stream ID and location) process activity are included for reconciliation. There should be no process activity reported for product Gas at gathering system locations.*

Example 1: EUB to OAS Gas Gathering System Reconciliation
(Shaded entries represent volumes subject to reconciliation)

EUB Monthly Gas Gathering Statement S8 System Code 2345 Yr/Mo.94/01

DISPOSITIONS									
PRO-RATED SALES						PRO-RATED DELIVERIES			
CONSUMER, RECYCLING, BATTERY/FACILITY		TRANSPORTERS EX-PROVINCE		DISTRIBUTOR		PROCESSING PLANT		INJECTION OR GATHERING SYSTEM	
9996	200.0*	5981	500.0	4901	400.0	1520	150.0	9841	80.0
9998	300.0					1901 ***	250.0	3350	70.0
0041519	50.0**					1801 ****	350.0	9997 *****	100.0

* *Lease fuel subject to royalty waiver (production volumes on OAS are net of this amount).*

** *Not subject to royalty waiver (volume must be reported on OAS as a sale).*

*** *Mainline Straddle Plant*

**** *Field Straddle Plant*

***** *Delivered for gas lift purposes, not subject to royalty (production volumes on OAS are net of this amount).*

OAS Reporting Facility AB-GS-2345 Opr 0020 Owner 0050 Production Yr/Mo.94/01

Stream ID	Stream Category	Location	Product	Activity	Volume	Destination
AB-WG-1	Production	AB-GS-2345	GAS	Sale	1250.0*	
AB-WG-2	Production	AB-GS-2345	GAS	Transfer**	150.0	AB-GP-1520
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	250.0	AB-GP-1901
AB-WG-2	Production	AB-GS-2345	GAS	Transfer**	350.0	AB-GP-1801
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	80.0	AB-IF-9841
AB-WG-2	Production	AB-GS-2345	GAS	Transfer**	70.0	AB-GS-3350

* *OAS sale volumes are from the following S8 pro-rated sales: 500.0+400.0+300.0+50.0 (exclude the 200 units eligible for royalty waiver).*

** *Transfer of unprocessed gas within the royalty network is optional reporting.*

NOTE: OAS VOLUMES ARE REPORTED NET OF THE LEASE FUEL WHICH IS SUBJECT TO ROYALTY WAIVER AND THE GAS LIFT VOLUMES, WHICH ARE REPORTED ON THE S8.

OAS Reconciliation

Facility: AB-GS-2345 **Business Associate: 0020**

Production Month: 1994-01 **Reconciliation Product: Gas Unit: 10^3m^3**

ALLOCATIONS FROM FACILITY ACTIVITY								**VOLUME**
Facility Activity Subject to Reconciliation								1530.0
TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY								**1530.0**
ALLOCATIONS ACCOUNTED ON OAS								
OAS Fac	**Filing Date**	**Owner**	**Stream ID**	**Stream Category**	**Activity**	**Destination**	**Product**	
AB-GS-2345	1994-05-10	0050	AB-WG-1	Production	Sale		Gas	1250.0
AB-GS-2345	1994-05-10	0050	AB-WG-2	Production	Transfer	AB-GP-1901	Gas	250.0
AB-GS-2345	1994-05-10	0050	AB-WG-2	Production	Transfer	AB-IF-9841	Gas	80.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**1580.0**
VOLUME DISCREPANCY								**(50.0)***

* *Discrepancy resulting from an understatement of "S" volumes due to the royalty payable lease fuel sale (Consumer, recycling, battery/facility-non Code 9998 sale), which is excluded from the "S" volumes but reported on the OAS.*

3.2 EUB to OAS Gas Processing Plant (Including Field Straddle Plant) Reconciliation (S20 to OAS)

The EUB to OAS reconciliation of "Gas" volumes for gas processing plants (including field straddle plants) is based on net plant dispositions. EUB "S" volumes used in this reconciliation are S20 gas disposition volumes, which are net of processing **shrinkage*** and system use. They include pro-rated sales to consumers, distributors and transporters, pro-rated deliveries to injection systems, gas plants, and gathering systems.

The OAS volumes participating in this reconciliation are those volumes "processed" at the facility plus any "flow-through" volumes at that facility.

Flow-through volumes are dispositions at the facility that have not been processed at that facility. The volumes processed at the facility are to be reported as "process" volumes on the OAS. The flow-through volumes are to be reported on the OAS as either "transfer" or "sale" volumes, depending on how the flow-through volumes are disposed at the facility. In order to accurately identify flow-through volumes, the Department requires all such volumes to be sourced back to the well ownership level.

The reconciliation can be summarized by the following equations:

Reconciliation Facility: Processing Plant (Including Field Straddle)

Reconciliation Product: Gas

S20: Pro-rated Gas sales except lease fuel sales

...plus...

Pro-rated Gas deliveries except Codes 9996/9997

...equals...

OAS: "Process" volumes for Gas

...plus...

"Transfer" volumes for Gas associated with streams that have not been processed at the reconciliation facility

...plus...

"Sale" volumes for Gas associated with streams that have not been processed at the reconciliation facility

NOTE: LEASE FUEL DISPOSITIONS MAY OR MAY NOT BE SUBJECT TO ROYALTY, (E.G., LEASE FUEL ELIGIBLE FOR ROYALTY WAIVER; *REFER TO SECTION 5.2*). WHERE SOME OR ALL OF THESE VOLUMES ARE ROYALTY DUE, THE FACILITY OPERATOR MUST REPORT THEM ON THE OAS. THE VOLUMES WILL APPEAR AS A CROWN FAVOUR DISCREPANCY SINCE THE OAS VOLUMES WILL BE INCLUDED BUT NOT THE CORRESPONDING S20 VOLUMES. NO ACTION IS REQUIRED ON THIS PARTICULAR CROWN FAVOR DISCREPANCY.

For definition, please see Appendix N - Glossary

GAS VOLUMES SUBJECT TO EUB/OAS GAS PROCESSING PLANT RECONCILIATION						
Recon Facility Type	**Recon Product**	**Facility Activity (S) Volumes**	**Oas Volumes**			
			Stream ID	**Str. Category**	**Activity**	**Destination**
GP	Gas	- S20 Pro-rated Sales-Consumers or Distributors or Transporters: all codes/volumes - S20 Pro-rated Deliveries-Recycling, Gas Lift, Injection System, Gas Plant, Gathering System-all codes/volumes except codes 9996/9997 volumes	all valid Stream ID types for reported stream category	by-product, cascade, gas, production, purchase	Process	n/a
			all valid Stream ID types for reported stream category*	by-product, cascade, gas, production, purchase, storage	Sale**	All
			all valid Stream ID types for reported stream category*	by-product, cascade, gas, production, purchase, storage	Transfer **	All

* *Only sale and transfer activities where there is no corresponding (i.e., same owner, Stream ID and location) process activity are included for reconciliation.*

** *The Department requires all processed gas flowing through a facility without being processed at the facility to be sourc[illegible] back to the well ownership level. If reported stream category is GAS, only Stream IDs that are sourced back to type W[illegible] WG, UN or IS will be included in the reconciliation.*

Example 2 EUB to OAS Gas Processing Plant Reconciliation

(Shaded entries represent volumes subject to reconciliation)

EUB Monthly Gas Processing Statement S20 System Code 1045 Yr./Mo. 94/01

DISPOSITION										
PRO-RATED SALES					PRO-RATED DELIVERIES					
LEASE FUEL			CONSUMERS OR DISTRIBUTORS OR TRANSPORTERS		RECYCLING, GAS LIFT OR INJECTION SYSTEM		GAS PLANT		GATHERING SYSTEM	
Field	Gathering System/Battery	Volume	Code	Net Quantity	Code	Volume	Code	Net Quantity	Code	Volume
004	0041519	100.0*	5981	200.0	9997***	150.0	1510	250.0	3133	300.0
			4901	500.0**	9845	90.0	1950	75.0		
							1801	50.0		

* *Lease fuel subject to royalty waiver (production volumes on OAS are net of this amount).*

** *Disposition not processed at this plant (i.e., flow-through volume).*

*** *Delivered for gas lift purposes, not subject to royalty (production volumes on OAS are net of this amount).*

OAS Reporting Facility AB-GP-1045 Opr 0010 Owner 0010 Production Year Yr./Mo. 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-WG-1	Production	AB-GP-1045	GAS	Process	965.0*	
	Gas	AB-GP-1045	GAS	Sale	200.0	
AB-WG-2	Gas	AB-GP-1045	GAS	Sale	500.0**	
AB-WG-1***	Gas	AB-GP-1045	GAS	Transfer	90.0	AB-IF-9845
AB-WG-1****	Gas	AB-GP-1045	GAS	Transfer	250.0	AB-GP-1510
AB-WG-1***	Gas	AB-GP-1045	GAS	Transfer	75.0	AB-GP-1950
AB-WG-1***	Gas	AB-GP-1045	GAS	Transfer	50.0	AB-GP-1801
AB-WG-1****	Gas	AB-GP-1045	GAS	Transfer	300.0	AB-GS-3133

* *OAS process volumes are from the following S20 pro-rated sales/deliveries: 200.0+90.0+250.0+75.0+50.0+300.0 (exclude lease fuel 200.0, gas lift 150.0 and flow-through gas 500.0).*

** *Flow-through volume must be sourced back to WI, WG, UN, or IS level to differentiate from volumes processed at the plant.*

*** *Stream ID is optional reporting for gas that is subsequently transferred out of royalty network after processing.*

**** *Stream ID must be sourced back to WI, WG, UN, or IS level for gas subsequently transferred within royalty network after processing in order to defer royalties to downstream facilities.*

OAS Reconciliation

Facility: AB-GP-1045
Production Month: 1994-01
Business Associate: 0010
Reconciliation Product: Gas
Unit 10^3m^3

ALLOCATIONS FROM FACILITY ACTIVITY								**VOLUME**
Facility Activity Subject to Reconciliation								1465.0
TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY								**1465.0**
ALLOCATIONS ACCOUNTED ON OAS								
OAS Facility	Filing Date	Owner	Stream ID	Stream Category	Activity	Destination	Product	
AB-GP-1045	1994-05-10	0010	AB-WG-1	Production	Process		Gas	965.0
AB-GP-1045	1994-05-10	0010	AB-WG-2	Gas	Sale		Gas	500.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**1465.0**
VOLUME DISCREPANCY								**0.0**

3.3 By-Product Reconciliation (S21 to OAS)

The EUB to OAS reconciliation of **"By-Product"*** volumes for gas processing plants (including field straddle plants) is based on the monthly production volumes of each by-product. EUB "S21" volumes for each by-product which are reported as monthly production are compared to the OAS volume quantities reported for that facility which represent monthly production volumes. These quantities are to be reported as "PROCESS" volumes on the OAS.

By-products can at times appear at the gathering system, before any plant processing takes place. In such cases, the operator will file an S21 reporting these by-products, and must also report them as an activity "PROCESS" on the OAS. These volumes will be reconciled in the same manner as gas for processing plants.

Reconciliation Facility: Gas Plant or Gathering System
Reconciliation Product: *Any* By-Product*
S21: Monthly production for by-product
...equals...
OAS: "Process" volumes for by-product

* *A separate reconciliation is done for each by-product or by-product roll-up.*

Recon Facility Type	Recon Product	Facility Activity (S) Volumes	Stream ID	Str. Category	Activity	Destination
GP, GS	Any By-Product	-S21 Monthly Production	all valid Stream ID types for reported stream category	by-product, cascade, gas, production, purchase	Process	n/a

****For definition, please see Appendix N - Glossary***

Example 3 EUB to OAS Gas Processing Plant Reconciliation for By-Product

(Shaded entries represent volumes subject to reconciliation)

EUB Monthly Gas Processing Plant Products Statement S21 System Code 1045
Yr/Mo.94/01

	SUPPLY	DISPOSITION		
SCHEDULE OF PRODUCTS	MONTHLY PRODUCTION	TO OTHER FACILITIES	FURTHER PROCESSING	TOTAL SHIPMENTS
Pentanes	160.0			160.0
NGL/LPG Mix	200.0		125.0	

OAS Reporting Facility AB-GP-1045 Opr 0010 Owner 0010 Production Yr/Mo.94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-WG-1	Production	AB-GP-1045	C5-SP	Process	160.0	
	By-product	AB-GP-1045	C5-SP	Sale	160.0	
AB-WG-1	Production	AB-GP-1045	C4-MX	Process	45.0	
AB-WG-1	Production	AB-GP-1045	C5-MX	Process	80.0	
	By-product	AB-GP-1045	NGL/LPG	Transfer	125.0	AB-GP-1703

OAS Reconciliation
Facility: AB-GP-1045 **Business Associate: 0010**
Production Month: 1994-01 **Reconciliation Production: Pentanes + Unit: m^3**

<table>
<tr><th colspan="8">ALLOCATIONS FROM FACILITY ACTIVITY</th><th>VOLUME</th></tr>
<tr><td colspan="8">Facility Activity Subject to Reconciliation</td><td>160.0</td></tr>
<tr><td colspan="8">TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY</td><td>160.0</td></tr>
<tr><td colspan="8">ALLOCATIONS ACCOUNTED ON GAS</td><td></td></tr>
<tr><td>OAS Fac</td><td>Filing Date</td><td>Owner</td><td>Stream ID</td><td>Stream Category</td><td>Activity</td><td>Destination</td><td>Product</td><td></td></tr>
<tr><td>AB-GS-2345</td><td>1994-05-10</td><td>0050</td><td>AB-WG-1</td><td>Production</td><td>Process</td><td></td><td>C5-SP</td><td>160.0</td></tr>
<tr><td colspan="8">TOTAL ALLOCATIONS ACCOUNTED ON OAS</td><td>160.0</td></tr>
<tr><td colspan="8">VOLUME DISCREPANCY</td><td>0.0</td></tr>
</table>

Production Month: 1994-01 **Reconciliation Production: NGL/LPG Mix Unit: m^3**

ALLOCATIONS FROM FACILITY ACTIVITY								**VOLUME**
Facility Activity Subject to Reconciliation								200.0
TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY								**200.0**
ALLOCATIONS ACCOUNTED ON OAS								
OAS Fac	Filing Date	Owner	Stream ID	Stream Category	Activity	Destination	Product	
AB-GP-1045	1994-05-10	0010	AB-WG-1	Production	Process		C4-MX	45.0
AB-GP-1045	1994-05-10	0010	AB-WG-1	Production	Process		C5-MX	80.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**125.0**
VOLUME DISCREPANCY								**75.0***

* *Valid discrepancy; client 0010 must amend.*

3.4 EUB to OAS Injection Facility Reconciliation (S18 to OAS)

The EUB to OAS reconciliation for injection facilities is based on all royalty product volumes received at the injection facility, which are for the purpose of injection. They are receipt volumes at the injection facility that are either injected or consumed during the process of injecting product(s) into an injection scheme. They exclude any subsequent sale/delivery of volumes from the injection facility.

The OAS volumes subject to reconciliation are reported as either "transfer" volumes received at the injection facility or "purchase" volumes received at the injection facility (where there is purchasing of injection stream for injection). These OAS transfer/purchase volumes represent the volumes injected as well as any fuel or flare, and any metering difference. The OAS transfer/purchase volumes exclude any subsequent sales/deliveries at the injection facility.

The reconciliation can be summarized by the following equation:

Reconciliation Facility: Injection Facility Reconciliation Product: *Any* Product*
S18: Receipts for product
...minus...
Other Deliveries for product (exclude product "solvent")
...equals...
OAS: "Transfer"** volumes for product received at injection facility for injection purpose
...plus...
"Purchase"** volumes for product received at injection facility for injection purpose

NOTE: IF S18 "DETAIL OF OTHER DELIVERIES" ARE FOR PRODUCT "SOLVENT", THESE SALES/DELIVERIES WILL NOT BE SUBTRACTED FROM THE S18 "RECEIPT" VOLUMES IN THE RECONCILIATION. WHEN BY-PRODUCTS ARE RECEIVED AT THE INJECTION FACILITY, THEY ARE REPORTED ON THE S18 IN THEIR RESPECTIVE UNIT OF MEASUREMENT (IE. M^3 OR 10^3M^3); HOWEVER, THE SALES/DELIVERIES OF GAS BY-PRODUCTS ARE REPORTED ON THES18 AS PRODUCT "SOLVENT" IN GAS EQUIVALENT VOLUMES. IN ORDER TO DEDUCT THE DELIVERIES FROM THE RECEIPT VOLUMES,A VOLUME CONVERSION IS REQUIRED. AT PRESENT, THE SYSTEM IS NOT CAPABLE TO CONVERT THE SOLVENT TO THE RESPECTIVE GAS BY-PRODUCT COMPONENT, AND THEREFORE, ANY "OTHER DELIVERIES" OF SOLVENT WILL BE EXCLUDED FROM THE BY-PRODUCT RECONCILIATION. IF THERE ARE SALES/DELIVERIES OF SOLVENT, THE DEPARTMENT EXPECTS THE FACILITY OPERATOR TO EXCLUDE THESE VOLUMES FROM THE TRANSFER/PURCHASE VOLUMES ON THE OAS. THIS WILL RESULT IN A CROWN FAVOR DISCREPANCY FOR WHICH NO ACTION IS REQUIRED.

* *A separate reconciliation is done for each product or product roll-up (see Appendix A, Section 8).*

** *Volumes are net of any subsequent sales/deliveries from the injection facility. They include the volumes injected and any fuel, flare or meter difference during the process of injection.*

PRODUCT VOLUMES SUBJECT OT EUB/OAS RECONCILIATION						
Recon facility type	Recon Product	Facility Activity (S) Volumes	OAS Volumes			
			Stream ID	Str. Category	Activity	Destination
IF	Any Royalty Product	- S18 receipts less S18 other deliveries* for product	all valid Stream ID types for reported stream category	Injection	Transfer	Injection Facility being reconciled
			all valid Stream ID types for reported stream category	Injection	Purchase	Injection Facility being reconciled

* *Exclude S18 other deliveries of product "solvent".*

Example 4 EUB to OAS Injection Facility Reconciliation

(Shaded entries represent volume subject to reconciliation)

EUB Monthly Injection/Disposal Statement S18 **System Code 9825** **Yr./Mo. 94/01**

DETAILS OF RECEIPTS			DETAILS OF OTHER DELIVERIES		
BATTERY/ FACILITY	PRODUCT*	RECEIPT VOLUME	BATTERY/ FACILITY	PRODUCT*	DELIVERY VOLUME
2310	Gas	1000.0 10^3m^3	1004	Gas	100.0 10^3m^3
2310	NGL/LPG	6000.0 m^3**	1004	Solvent	200.0 10^3m^3

FACILITY SUMMARY (in gas equivalents)

PRODUCT*	TOTAL RECEIPTS	OPENING INVENTORY	CLOSING INVENTORY	TOTAL OTHER DELIVERIES	FLARED	LEASE FUEL	METER INDIFF	TOTAL INJECTION DISPOSAL
Gas	1000.0			100.0	5.0	10.0	15.0	870.0
Solvent	1200.0			200.0**				1000.0***

* *Product name will be used instead of actual S18 product code for ease of understanding.*

** *Assume gas equivalent volume = 1200.0 10^3m^3 (conversion factor of 0.2 used).*

*** *Assume other deliveries = 1000.0 m^3, injection/disposal = 5000.0 m^3.*

OAS Reporting Facility AB-IF-9825 Opr HA40 Owner HA40 Production Yr./Mo. 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-IS-11519	Injection	AB-GS-2310	Gas	Transfer	300.0*	AB-IF-9825
AB-IS-11519	Injection	AB-GS-2310	Gas	Purchase**	600.0*	AB-IF-9825
AB-IS-11519	Injection	AB-GS-2310	C2-MX	Transfer	1000.0*	AB-IF-9825
AB-IS-11519	Injection	AB-GS-2310	C4-MX	Transfer	4000.0*	AB-IF-9825
AB-IS-11519	Injection	AB-IF-9825	Gas	Injection	870.0	
AB-IS-11519	Production	AB-IF-9825	Gas	Transfer	40.0	AB-GP-1004
AB-IS-11519	Injection	AB-IF-9825	NGL/LPG	Injection	5000.0	AB-IF-9825

* *Volumes include amount injected and consumed during process of injection only, they exclude any other deliveries from the injection facility (fuel, flare, metering may be shown on this OAS, reporting is optional).*

** *To demonstrate that 600.0 units have been purchased for the purpose of injection.*

OAS Reconciliation
Facility: AB-IF-9825 **Business Associate: HA40**
Production Month: 1994-01 **Reconciliation Product: Gas** **Unit: 10^3m^3**

ALLOCATIONS FROM FACILITY ACTIVITY								**VOLUME**
Facility Activity Subject to Reconciliation								900.0
TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY								**900.0**
ALLOCATIONS ACCOUNTED ON OAS								
OAS Fac	Filing Date	Owner	Stream ID	Stream Category	Activity	Destination	Product	
AB-IF-9825	1994-05-10	HA40	AB-IS-11519	Injection	Transfer	AB-IF-9825	Gas	300.0
AB-IF-9825	1994-05-10	HA40	AB-IS-11519	Injection	Purchase	AB-IF-9825	Gas	600.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**900.0**
VOLUME DISCREPANCY								**0.0**

Product Month: 1994-01 **Reconciliation Product: NGL/LPG Mix** **Unit: m^3**

ALLOCATIONS FROM FACILITY ACTIVITY								**VOLUME**
Facility Activity Subject to Reconciliation								6000.0
TOTAL ALLOCATIONS RECEIVED FROM FACILITY ACTIVITY								**6000.0**
ALLOCATIONS ACCOUNTED ON OAS								
OAS Fac	Filing Date	Owner	Stream ID	Stream Category	Activity	Destination	Product	
AB-IF-9825	1994-05-10	HA40	AB-IS-11519	Injection	Transfer	AB-IF-9825	C2-MX	1000.0
AB-IF-9825	1994-05-10	HA40	AB-IS-11519	Injection	Transfer	AB-IF-9825	C4-MX	4000.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**5000.0**
VOLUME DISCREPANCY								**(1000.0)***

- *Discrepancy resulting from an overstatement of "S" volumes due to S18 other deliveries of "solvent" not subtracted from the S18 NGL/LPG mix receipts but deducted from the OAS volumes (OAS volumes are properly accounted).*

4. OAS Cascade Reconciliation (OAS to OAS Volume Reconciliation)

The OAS Cascade Reconciliation refers to OAS volumes that have been cascaded to an upstream facility operator. Each facility operator who has received cascaded volumes must account for them in one of two ways:

- the same quantities must be further cascaded upstream; or
- the quantities must be allocated to a *Well Event, Unit, Injection Scheme, or Well Group.*

The cascaded volumes reported by the downstream operator are then reconciled to the OAS volumes reported by the upstream operator. The operator of the upstream facility will be provisionally assessed for any cascaded quantities not accounted for by one of these methods.

The OAS volumes are reconciled by product. Only the OAS volumes that are included in the EUB to OAS reconciliation would be included in the OAS cascade reconciliation. Network sales that are cascaded upstream are also not included in this reconciliation.

The reconciliation can be summarized by the following equation:

Reconciliation Facility: Any location facility where cascading took place
Reconciliation Product: *Any* Product*
OAS: OAS volumes from "EUB to OAS Reconciliation" which are cascaded to upstream facility operator
...equals...
OAS:
OAS volumes from "EUB to OAS Reconciliation" accounted for by upstream facility operator

* *A separate reconciliation is done for each product or product roll-up.*

PRODUCT VOLUMES SUBJECT TO OAS CASCADE RECONCILIATION							
Recon Facility Type*	Recon Product	Receiving Opr	OAS Volumes				
			Received from Cascade		Accounted by Receiving Opr		
			Str. Category	Activity	Stream ID/ Category	Location	Activity
GS, GP	Products subject to EUB to OAS reconciliation	- reported owner on OAS of product stream where stream category is Cascade	Cascade	- applicable Process, Sale & Transfer subject to EUB to OAS reconciliation	- as defined in the applicable EUB to OAS reconciliation	- same location as the location of the OAS "received from cascade" volumes	- applicable Process, Sale & Transfer subject to EUB to OAS recon which are reported by receiving operator

- *This reconciliation does not apply to injection facilities since injection streams receipted as the injection facility are not cascaded by the facility operator.*

Example 5 OAS Cascade Reconciliation

(Shaded entries represent volume subject to reconciliation)

Opr 0020 is reporting activities for Gathering System AB-GS-2345 on the OAS. The operator cannot source the production volumes back to the well ownership level so the volumes are cascaded to the facility operator upstream (Opr AD10). The upstream operator must either source the product stream back to the well ownership level or cascade it to another operator upstream from his facility. This example shows the upstream operator sourcing the product stream back to the well ownership level.

OAS Reporting Facility AB-GS-2345 Opr 0020 Owner AD10 Production Yr./Mo. 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Sale	1250.0	AB-TF
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Transfer	150.0	AB-GP-1520
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Transfer	250.0	AB-GP-1901
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Transfer	350.0	AB-GP-1801
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Transfer	80.0	AB-IF-9841
AB-BT-0041917	Cascade	AB-GS-2345	GAS	Transfer	70.0	AB-GS-3350
AB-BT-0041917	Cascade	AB-GS-2345	C5-SP	Process	160.0	
AB-BT-0041917	Cascade	AB-GS-2345	C5-SP	Sale	160.0	

OAS Reporting Facility AB-BT-0041917 Opr AD10 Owner 0050 Production Yr./Mo.94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-WG-1	Production	AB-GS-2345	GAS	Sale	1250.0	AB-TF
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	150.0	AB-GP-1520
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	250.0	AB-GP-1901
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	350.0	AB-GP-1801
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	80.0	AB-IF-9841
AB-WG-2	Production	AB-GS-2345	GAS	Transfer	70.0	AB-GS-3350
AB-WG-1	Production	AB-GS-2345	C5-SP	Process	160.0	
	By-product	AB-GS-2345	C5-SP	Sale	160.0	

OAS Reconciliation
Facility: AB-GS-2345 **Business Associate: AD10**
Production Month: 1994-01 **Reconciliation Product: Gas** **Unit: 10^3m^3**

ALLOCATIONS RECEIVED FROM OAS CASCADE								**VOLUME**
OAS Facility	**Filing Date**	**Opr**	**Stream ID**	**Stream Category**	**Activity**	**Destination**	**Product**	
AB-GS-2345	1994-05-10	0020	AB-BT-0041917	Cascade	Sale	AB-TF	Gas	1250.0
AB-GS-2345	1994-05-10	0020	AB-BT-0041917	Cascade	Transfer	AB-GP-1901	Gas	250.0
AB-GS-2345	1994-05-10	0020	AB-BT-0041917	Cascade	Transfer	AB-IF-9841	Gas	80.0
TOTAL ALLOCATIONS RECEIVED FROM OAS CASCADE								**1580.0**

ALLOCATIONS ACCOUNTED ON OAS								
OAS Facility	**Filing Date**	**Owner**	**Stream ID**	**Stream Category**	**Activity**	**Destination**	**Product**	
AB-GS-2345	1994-05-10	0050	AB-WG-1	Production	Sale	AB-TF	Gas	1250.0
AB-GS-2345	1994-05-10	0050	AB-WG-2	Production	Transfer	AB-GP-1901	Gas	250.0
AB-GS-2345	1994-05-10	0050	AB-WG-2	Production	Transfer	AB-IF-9841	Gas	80.0
TOTAL ALLOCATIONS ACCOUNTED ON OAS								**1580.0**
VOLUME DISCREPANCY								**0.0**

NOTE: RECONCILIATION IS DEMONSTRATED ONLY FOR RECONCILIATION PRODUCT GAS. HOWEVER, OTHER RECONCILIATION PRODUCTS ARE RECONCILED SIMILARLY.

5. Purchase to Sale Reconciliation (In-Network Purchase/Sale Reconciliation)

Sales that occur within the royalty network have corresponding product movements to destinations that are considered to be inside the royalty network. In all cases, the location of the sale is deemed to be upstream of the destination.

The Purchase to Sale reconciliation compares OAS volumes purchased within the royalty network to the corresponding OAS volumes sold. These volumes are represented as "purchase" and "sale" activities on the OAS. The activities should reference the same OAS location/destination since the purchase and sale relate to the same transaction.

The reconciliation is performed for each location and destination where a purchase within the royalty network is reported. The operator of the facility where the sale/purchase took place (location) is responsible for reporting the sale and purchase portion of the transaction. Any provisional assessment resulting from purchased volumes not supported by corresponding sales, will be assessed against the operator of the facility where the sale took place.

Purchase-to-Sale reconciliation is performed for product Gas only. By-product sales within the royalty network have no royalty obligations since the royalties have been collected on the by-product when they are extracted from the gas stream.

The reconciliation can be summarized by the following equation:

Reconciliation Facility: Facility reporting "In-Network" purchase/sale
Reconciliation Product: Gas

OAS: Gas "Purchase" volumes at location where the destination of the purchase is within royalty network

...equals...
OAS: GAS "Sale" volumes where location and destination match that of the "purchase" volumes

PRODUCT VOLUMES SUBJECT TO PURCHASE-TO-SALE RECONCILIATION				
OAS Volumes				
Stream Category	**Location**	**Recon Product**	**Activity**	**Destination**
Purchase	Any	Gas	Purchase	Type = BT, GS, GP (not mainline straddle or fractionation plant)
Gas, Production, Purchase, Storage	- same location ID as location ID of Purchase Activity	Gas	Sale	- same destination ID as destination ID of Purchase Activity

Example 6 Purchase to Sale Reconciliation

(Shaded entries represent volume subject to reconciliation)

This example indicates a purchase and a sale taking place within the royalty network. Unprocessed gas is sold at the gathering system and the product stream is taken to a gas plant for processing. Client 0020 (operator of GP 1008) purchases the product stream from Client 0050 (operator of GS 3416) and takes the product stream to his gas plant for processing. The processed gas is then sold.

Scenario 1: Operator of selling facility reports purchase and sale

OAS Reporting Facility AB-GS-3416 Opr 0050 Owner 0050 Production Yr/Mo 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-WG-1	Production	AB-GS-3416	Gas	Sale	200.0	AB-GP-1008

OAS Reporting Facility AB-GS-3416 Opr 0050 Owner 0020 Production Yr/Mo 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
AB-WG-1	Purchase	AB-GS-3416	Gas	Purchase	200.0	AB-GP-1008

Operator of purchasing facility will report as follows:

OAS Reporting Facility AB-GP-1008 Opr 0020 Owner 0020 ProductionYr/Mo 94/01

Stream ID	Stream Category	Location	Product	Activity	Net Quantity	Destination
	Purchase	AB-GP-1008	Gas	Process	180.0	
	Purchase	AB-GP-1008	Gas	Sale	180.0	

Purchase to Sale Reconciliation
Location: AB-GS-3416 **Destination: AB-GP 1008** **Operator ID: 0050***
Production Month: 1994-01 **Reconciliation Product: Gas** **Unit: 10^3m^3**

GAS PURCHASED WITHIN ROYALTY NETWORK						**VOLUME**
Reporting OAS Fac	**Filing Date**	**Opr**	**Owner**	**Stream ID**	**Stream Category**	
AB-GP-1008	1994-05-10	0020	0020	AB-WG-1	Purchase	200.0
TOTAL GAS PURCHASED WITHIN ROYALTY NETWORK						200.0
GAS SALES WITHIN ROYALTY NETWORK						
Reporting OAS Fac	**Filing Date**	**Opr**	**Owner**	**Stream ID**	**Stream Category**	
AB-GP-1008	1994-05-10	0020	0020	AB-WG-1	Purchase	200.0
TOTAL GAS PURCHASED WITHIN ROYALTY NETWORK						
VOLUME DISCREPANCY						

* *Operator of facility where sale took place.*

Scenario 2: **Operator of purchase facility reports purchase and sale**

OAS **Reporting Facility AB-GP-1008** **Opr 0050** **Owner 0050** **Production Yr/Mo. 94/01**

Stream ID	**Stream Category**	**Location**	**Product**	**Activity**	**Net Quantity**	**Destination**
AB-WG-1	Production	AB-GS-3416	Gas	Sale	200.0	AB-GP-1008

OAS **Reporting Facility AB-GP-1008** **Opr 0050** **Owner 0020** **Production Yr/Mo. 94/01**

Stream ID	**Stream Category**	**Location**	**Product**	**Activity**	**Net Quantity**	**Destination**
AB-WG-1	Purchase	AB-GS-3416	Gas	Purchase	200.0	AB-GP-1008

OAS **Reporting Facility AB-GP-1008** **Opr 0020** **Owner 0020** **Production Yr/Mo. 94/01**

Stream ID	**Stream Category**	**Location**	**Product**	**Activity**	**Net Quantity**	**Destination**
	Purchase	AB-GP-1008	Gas	Process	180.0	
	Purchase	AB-GP-1008	Gas	Sale	180.0	

Purchase to Sale Reconciliation
Location: AB-GS-3416 **Destination: AB-GP-1008** **Operator ID: 0050***
Production Month: 1994-01 **Reconciliation Product: Gas** **Unit: $10^3 m^3$**

GAS PURCHASE WITHIN ROYALTY NETWORK						**VOLUME**
Reporting OAS Fac	**Filing Date**	**Opr**	**Owner**	**Stream ID**	**Stream Category**	
AB-GP-1008	1994-05-10	0020	0020	AB-WG-1	Purchase	200.0
TOTAL GAS PURCHASES WITHIN ROYALTY NETWORK						**200.0**
GAS SALES WITHIN ROYALTY NETWORK						
Reporting OAS Fac	**Filing Date**	**Opr**	**Owner**	**Stream ID**	**Stream Category**	
AB-GP-1008	1994-05-10	0020	0050	AB-WG-1	Production	200.0
TOTAL GAS SALES WITHIN ROYALTY NETWORK						**200.0**
VOLUME DISCREPANCY						**0.0**

* *Operator of facility where sale took place.*

6. Volumetric Reconciliation Discrepancy Letters

To assist facility operators in resolving volumetric reconciliation discrepancies, letters identifying the volume discrepancies and the supporting reconciliation details are sent to facility operators.

Two types of letters are generated. The "OAS Reconciliation Discrepancies" letter addresses volumetric discrepancies related to EUB to OAS or OAS Cascade reconciliations. The "Purchase to Sale Reconciliation Discrepancies" letter addresses volumetric discrepancies related to Purchase-to-Sale reconciliations. The reconciliation discrepancies will be cleared once the appropriate OAS or EUB "S" document amendments have been filed.

7. Provisional Assessment for Volumetric Reconciliation Discrepancies

A provisional assessment will be levied on the facility operator for each volumetric reconciliation discrepancy that is greater than the designated volume tolerance at the time of invoicing. The provisional assessment is calculated as follows:

Volume Discrepancy
...multiplied by...
35%
...multiplied by...
Product Reference Price for the production month

Details concerning the calculation of provisional royalty compensation are given in *Section 26.1.3*.

8. Reconciliation Products

Volumetric reconciliation at a facility location will be performed for each reconciliation product listed below. The associated S and OAS Products are described for each reconciliation product. Product volumes will either be reconciled as individual products or rolled up with other products as an aggregate volume for reconciliation.

Reconciliation Product	**S Product**	**OAS Product Codes (based on PRIDE Release 3 codes)**
Butane (m^3)	Butane (m^3)	C4-SP IC4-SP NC4-SP
Carbon Dioxide* (m^3)	Carbon Dioxide	C02
Ethane (m^3)	Ethane	C2-SP
Gas (10^3m^3)	Gas	GAS
NGL/LPG Mix** (m^3)	NGL/LPG Ethane Plus (appear on S21) Ethane Plus (appear on S18)	LITEMX C2-MX C3-MX C4-MX IC4-MX NC4-MX C5-MX IC5-MX NC5-MX C6-MX
Pentanes + (m^3)	Pentanes Plus Condensate (appear on S18)	C5-SP IC5-SP NC5-SP C6-SP
Propane (m^3)	Propane	C3-SP
Sulphur (tonnes)	Sulphur	S or SUL SBASE SBLOC SFORM SMOLT SPRILL SLATE

- *$C0_2$ will be rolled up with Gas in gas gathering system and processing plant reconciliations because S8/S20 dispositions sometimes contain carbon dioxide volumes which are reported as part of the gas disposition on the S documents, and as a $C0_2$ product volume on the OAS. The Reconciliation Product resulting from this product roll-up will be "Gas". Any volume subject to provisional assessment will be assessed as product Gas. This roll-up is not required for injection facility reconciliation, as S18 addresses $C0_2$ as a separate product.*
- *NGL/LPG mix discrepancy volumes subject to provisional assessment will be assessed as Pentanes.*

OAS Royalty Triggers and OAS Reporting Rules for Royalty Assessment

1. Introduction

The Alberta Department of Resource Development (the Department) has agreed that the reporting requirements established by PRIDE for the OAS will be adopted for royalty assessment. Using the OAS data provided by facility operators, the Department assesses royalty at facilities for the owner of each product stream. Assessment is primarily based on what happens at a facility. Different royalty assessment methods are used depending on whether the previously unsold product stream is processed or unprocessed.

2. Purpose

The purpose of *Appendix B* is to outline the Department royalty triggers and illustrate certain OAS reporting concepts that are fundamental to accurate royalty assessment.

3. Intended Audience

Appendix B is structured to provide information at the detailed level. It is designed to be used as a *practical guide* to aid in understanding how royalty will be triggered from OAS data and to clarify certain OAS reporting requirements that are necessary for accurate royalty assessment. The intended audience is the production accounting work level.

4. The Department Terms and Definitions

A review of the following terms and definitions is beneficial to understanding the material presented in *Appendix B*. These terms and definitions are to be used within the context of royalty assessment by the Department and may not have universal application.

4.1 Royalty Network

The royalty network is a collection of interconnected processing and gathering facilities that receive products either directly or indirectly from reservoirs. The network (for Department royalty purpose) is deemed to end when the product is delivered to:

- Commercial Transportation Facilities such as pipelines, railcars, and trucks;
- Field Straddle Plants (except in the case of unprocessed product where the network is deemed to end at the field straddle plant outlet gate, whether or not any processing of the product occurs);
- Mainline Straddle Plants;
- Fractionation Plants;
- Injection Facilities;
- Facilities outside the Province of Alberta (except non-Alberta facilities on the Department approval list); *and*
- Refineries, Terminals, Treating Plants.

4.2 Processing

- Processing is the action of creating new product(s) from existing product(s) by:
- extracting component gases and/or liquids from a product;
- combining two or more products; *and*
- Altering the state in which a product exists (i.e., changing a product from a gaseous state to a liquid state).

Processing excludes the separation and/or recombination of product(s) produced at a well that is necessary for the purpose of an initial measurement and transportation.

4.3 Unsold Stream

A movement of product originating at a reservoir and moving through a network to the point where ownership of the product change hands.

4.4 Unprocessed Stream

A movement of effluent recovered from a formation in any form (gas, liquid or solid). Effluent becomes an unprocessed stream for reporting after the first point of measurement.

4.5 Processed Stream

A processed stream originates at the first point where the product stream is processed after the initial wellhead separation/measurement point.

4.6 Purchased Stream*

A movement of product originating at the point where ownership changed from one business associate (legal entity) to another. A stream can be purchased and sold several times within the network.

4.7 OAS Stream Category "Production"

An unsold, unprocessed product stream, composed of products recovered from a formation in gaseous or liquid form, which originates at the first point of measurement after the wellhead, and ends at the first processing point.

4.8 OAS Stream Category "Gas"

An unsold and processed product stream, composed mainly of methane, which is left over after natural gas is processed (residue gas). Natural gas is processed in order to remove heavier components (natural gas liquids), hydrogen sulphide and/or other impurities from the gas. The residue is the portion of the original gas which remains after processing.

4.9 OAS Stream Category "By-product"

By-product streams can exist in any form (i.e., gas, liquid, solid). A product stream changes from *production* or *gas* to *by-product* at the processing point where the new product is created from the input product(s).

4.10 IN-NET Facility (within royalty network)

A facility location on OAS where OAS Province Code = AB, Type Code = BT/GS/GP. The GP referenced here is a conventional gas processing plant.

4.11 OUT-NET Facility (outside of royalty network)

A facility location on OAS where OAS Province Code = AB, Type Code = IF/RF/TM/PL/RR/TR or a gas plant - (GP) which is a mainline or fractionation plant, or a non-Alberta facility location.

5. Legends Used in This Section:

→	delivery to a facility
➡ or ➡	sale/exchange prior to delivery to a facility
☆ #	royalty trigger point (# denotes royalty trigger #)
△ #	injection credit point (# denotes royalty trigger #)
▲ #	eligible fuel consumption (# denotes royalty trigger #)
✚ #	royalty reduction - transfer within royalty network (# denotes royalty assessment method)
○ #	royalty reduction - fuel, flare, meter (# denotes royalty assessment method)

BT = Battery
GP = Gas Plant
GS = Gathering System
IF = Injection Facility
IS = Injection Scheme
PL = Pipeline
RF = Refinery
RR = Rail Road
TF = Transportation Facility
TM = Terminal
TR = Truck
UN = Unit
WG = Well Group
WI = Single Well

6. Royalty Triggers, Injection Credits, Other Royalty Reductions and Supporting Royalty Assessment Method Details

Royalty Triggers are based on what happens at the facility. The method of assessment depends on whether the product stream is processed or unprocessed, and on what is happening at the facility where the royalty assessment takes place. The royalty assessment methods chosen are the result of joint endeavours between the Department and the petroleum and gas industry. The following items identify the locations where the Department royalty assessment will be triggered when the described business events occur:

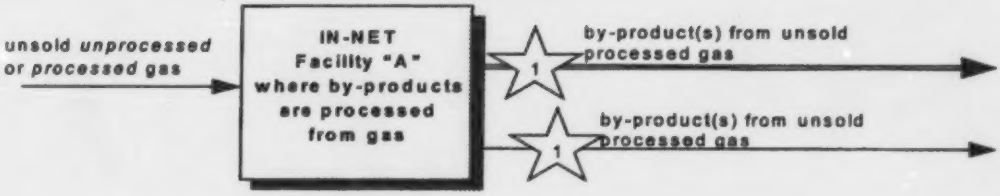
6.1 Royalty Trigger #1 - Facility By-Product Processing (excluding Straddle Plants)

Facility (excluding Straddle Plants) where any product except gas is extracted from a previously unsold gas stream.

Royalty Assessment Method for Royalty Trigger #1

For products *other than Gas* at a facility (excluding straddle and fractionation plants) where they are extracted from a previously unsold *gas* stream, stream royalty assessable volume equals:

volumes processed


unsold *unprocessed* or *processed* gas
IN-NET Facility "A" where by-products are processed from gas
by-product(s) from unsold processed gas
1
by-product(s) from unsold processed gas
1

OAS Reporting for Royalty Assessment Method #1

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS	Production	IN-NET Facility A	Other than GAS	PROC	Any	royalty charge	Loc. Fac.
AB-WI/WG/UN/IS	Gas	IN-NET Facility A	Other than GAS	PROC	Any	royalty charge	Loc. Fac.

6.2 Royalty Trigger #2 - Facility Disposition of Unsold Gas

Facility (excluding Straddle Plants) where previously unsold gas is:

- sold;
- delivered to Mainline Straddle Plants, Commercial Transportation Facilities, destinations such as refineries, terminals, treating plants, or non-Alberta facility locations; *or*
- delivered to Injection Facilities.

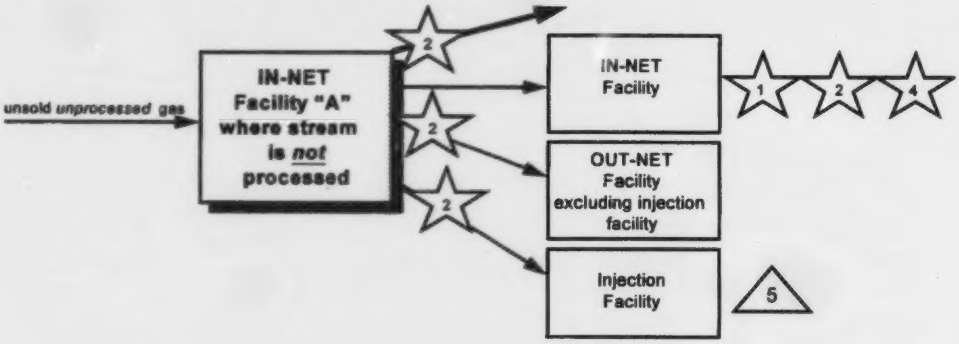
Royalty Assessment Methods for Royalty Trigger #2

Assessment method is based on whether the gas stream is processed or unprocessed upon receipt at facility and on what is happening to the stream at that facility. By-product streams resulting from processed by-products are not subject to royalty assessment because royalties were already charged when by-products are extracted from the gas stream.

2a. For previously unsold, *unprocessed* gas at a facility (excluding straddle and fractionation plants) where stream is *not processed*, stream royalty assessable volume equals:

> volumes sold
> ***...plus...***
> volumes exchanged
> ***...plus...***
> volumes transferred to Alberta Injection Facilities, Mainline Straddle Plants, Fractionation Plants, Refineries, Treating Plants, Terminals, Transportation Facilities and facilities that are not located in Alberta.

NOTE: VOLUMES DELIVERED TO OIL SAND PROJECTS (ROYALTY LIABLE) ARE EXPECTED TO BE REPORTED EITHER AS VOLUMES SOLD OR VOLUMES TRANSFERRED TO TRANSPORTATION FACILITIES ON OAS.


unsold unprocessed gas
IN-NET Facility "A" where stream is not processed
2
2
2
IN-NET Facility
1
2
4
OUT-NET Facility excluding injection facility
Injection Facility
5

OAS Reporting for Royalty Assessment Method 2a.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Production	IN-NET Facility A	GAS	SALE	Any	royalty charge**	Loc. Fac.
AB-WI/WG/UN/IS*	Production	IN-NET Facility A	GAS	EXCH***	Any	royalty charge***	Loc. Fac.
AB-WI/WG/UN/IS*	Production	IN-NET Facility A	GAS	TSF	OUT-NET Facility	royalty charge	Loc. Fac.

* *IS which is a Department-approved "Production Motivated" Injection Scheme only.*

** *Royalty volumes valued at 80% of Reference Price for Reference Price Filers if immediate Destination type = GP, or Destination = designated 80% valuation facilities per Department records. (Refer to Section 6.2 Gas Reference Price for raw gas.)*

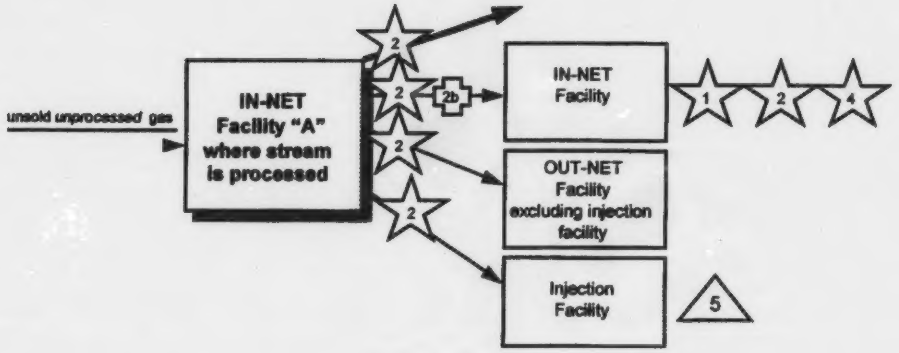
*** *Only exchanges with negative values are applicable. These represent quantities given up.*

2b. For previously unsold, *unprocessed* gas at a facility (excluding straddle and fractionation plants) where stream is *processed*, stream royalty assessable volume equals:

volumes processed

...minus...

volumes transferred to Alberta facilities *other than* Injection Facilities, Straddle Plants, Fractionation Plants, Refineries, Treating Plants, Terminals, Transportation Facilities and destinations that are ex-Alberta.


unsold unprocessed gas
IN-NET Facility "A" where stream is processed
2
2
2b
2
2
IN-NET Facility
1
2
4
OUT-NET Facility excluding injection facility
Injection Facility
5

OAS Reporting for Royalty Assessment Method 2b.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Production	IN-NET Facility A	GAS	PROC**	Any	royalty charge	Loc. Fac.
AB- WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty reduction	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty charge***	Dest. Fac.

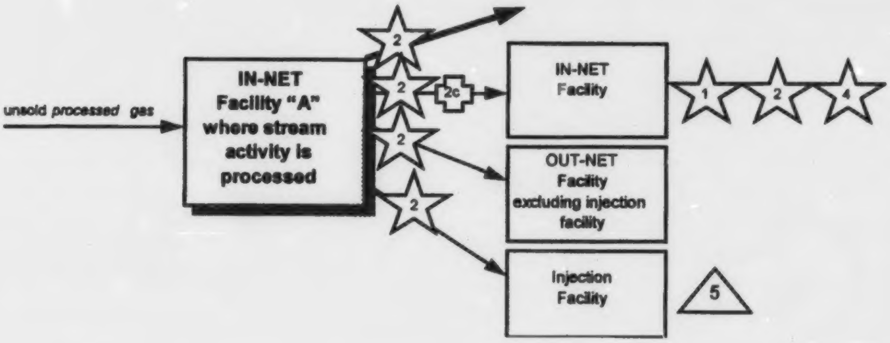
* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** *Gas dispositions at gathering systems are to be reported on the OAS as either a "Sale" or a "Transfer". There should be no "Process" activity reported at Location "BT" or "GS" for product GAS. If such records are reported, royalty will be charged.*

*** *Only applicable if the same product stream is not further processed at the destination facility.*

2c. For previously unsold, *processed* gas at a facility (excluding straddle and fractionation plants) where stream is *further processed*, the stream royalty assessable volume equals:

volumes processed
...minus...
volumes transferred to Alberta facilities *other than* Injection Facilities, Straddle Plants, Fractionation Plants, Refineries, Treating Plants, Terminals, Transportation Facilities and destinations that are ex-Alberta.


unsold processed gas
IN-NET Facility "A" where stream activity is processed
2
2
2c
2
2
IN-NET Facility
1
2
4
OUT-NET Facility excluding injection facility
Injection Facility
5

OAS Reporting for Royalty Assessment Method 2c.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	PROC**	Any	royalty charge	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty reduction	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty charge***	Dest. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** *Gas dispositions at gathering systems are to be reported on the OAS as either a "Sale" or a "Transfer". There should be no "Process" activity taking place at Location "BT" or "GS" for product GAS. If such records are reported, royalty will be charged.*

*** *Only applicable if same product stream is not further processed at the destination facility.*

2d. For previously unsold, *processed* gas at a facility (excluding straddle and fractionation plants) where there is *no further processing* of stream, the stream royalty assessable volume equals:

volumes received

...minus...

volumes transferred to Alberta facilities *other than* Injection Facilities, Straddle Plants, Fractionation Plants, Refineries, Treating Plants, Terminals, Transportation Facilities and destinations that are ex-Alberta.

...minus...

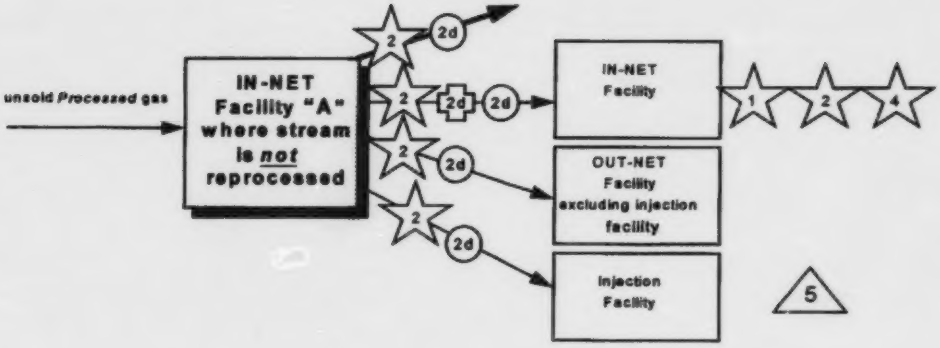
fuels consumed

...minus...

volumes flared

...minus...

metering difference (includes volumes vented and inventory adjustments)


unsold *Processed* gas
IN-NET Facility "A" where stream is *not* reprocessed
2
2d
2
2d
2d
2
2d
2
2d
IN-NET Facility
1
2
4
OUT-NET Facility excluding injection facility
Injection Facility
5

OAS Reporting for Royalty Assessment Method 2d.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Gas	IN-NET Facility Prior to A	GAS	TSF	IN-NET Facility A	royalty charge**	Dest. Fac.
AB- WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty reduction	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility B	royalty charge**	Dest. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	FUEL	Any	royalty reduction**	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	FLARE	Any	royalty reduction**	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	METER	Any	royalty reduction**	Loc. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** *Only applicable if the same product stream is not further processed at the assessment facility.*

6.3 Royalty Trigger #3 - Field Straddle Plant Gas Processing

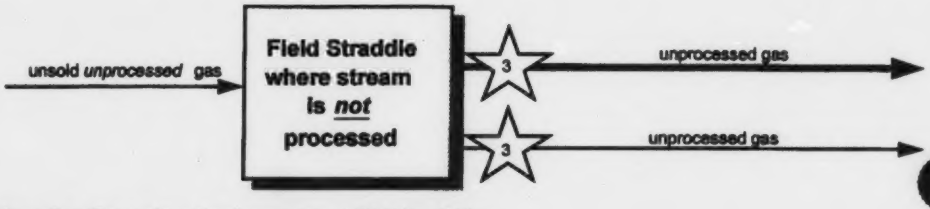
Field Straddle Plant where previously unsold, unprocessed gas is processed or disposed before processing occurs at the field straddle plant.

Royalty Assessment Methods for Royalty Trigger #3

Assessment method is based on what is happening to the unprocessed gas receipted at the Field Straddle Plant. Processed gas and by-product streams receipted for reprocessing are not subject to royalty assessment because royalties are charged at the facilities upstream from the Field Straddle Plant.

3a. For previously unsold, *unprocessed* gas at a Field Straddle Plant where stream activity is *not processed*, stream royalty assessable volume equals:

volumes sold
...plus...
volumes exchanged
...plus...
volumes transferred



OAS Reporting for Royalty Assessment Method 3a.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Production	AB-GP (field straddle)	GAS	SALE	Any	royalty charge**	Loc. Fac.
AB-WI/WG/UN/IS*	Production	AB-GP (field straddle)	GAS	EXCH***	Any	royalty charge***	Loc. Fac.
AB-WI/WG/UN/IS*	Production	AB-GP (field straddle)	GAS	TSF	Any	royalty charge	Loc. Fac.

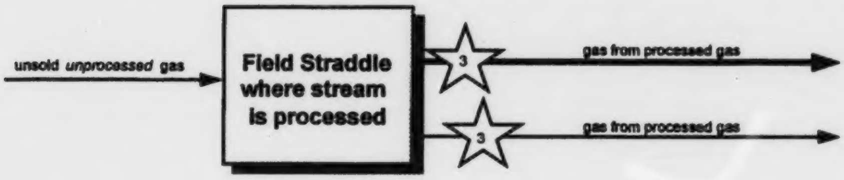
* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** *Royalty volumes valued at 80% of Reference Price for Reference Price Filers if immediate Destination type = GP, or Destination = designated 80% valuation facilities per Department records. (Refer to Section 6.2.)*

*** *Only exchanges with negative values are applicable. These represent quantities given up.*

3b. For previously unsold, *unprocessed* gas at a Field Straddle Plant where stream activity is *processed*, stream royalty assessable volume equals:

volumes processed


unsold *unprocessed* gas
Field Straddle where stream is processed
3
gas from processed gas
3
gas from processed gas

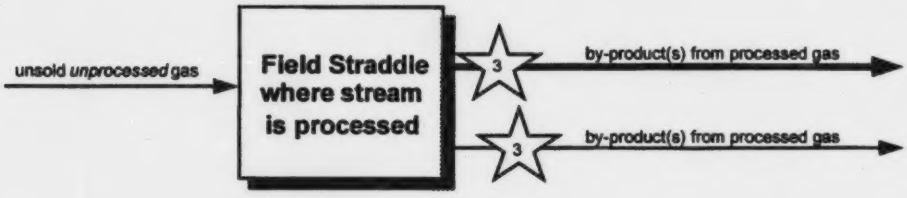
OAS Reporting for Royalty Assessment Method 3b.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Production	AB-GP (field straddle)	GAS	PROC	Any	royalty charge	Loc. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

3c. For products *other than Gas* at a Field Straddle Plant, where they are extracted from a previously unsold, *unprocessed gas* stream, royalty assessable volume equals:

volumes processed


unsold *unprocessed* gas
Field Straddle where stream is processed
3
by-product(s) from processed gas
3
by-product(s) from processed gas

OAS Reporting for Royalty Assessment Method 3c.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS	Production	AB-GP (field straddle)	Other than GAS	PROC	Any	royalty charge	Loc. Fac.

6.4 Royalty Trigger #4 - Facility Gas Disposition to Field Straddle Plant

Facility where previously unsold, processed gas is delivered to a Field Straddle Plant.

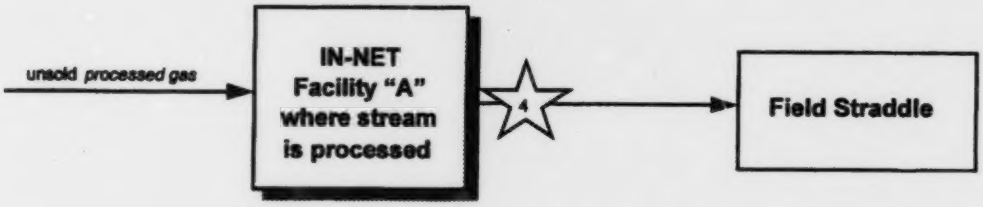
Royalty Assessment Methods for Royalty Trigger #4

Assessment method is based on whether the gas stream is processed or unprocessed upon receipt at facility, and on what is happening to the stream at the facility prior to delivery to the Field Straddle Plant. By-product streams resulting from processed by-products are not subject to royalty assessment because royalties would have been charged when by-products are extracted from the gas stream.

4a. For previously unsold, *unprocessed* gas at a facility (excluding straddle and fractionation plants) where stream activity is *processed* and is subsequently delivered to a Field Straddle Plant, stream royalty assessable volumes equals:

volumes processed

NOTE: NO ROYALTY REDUCTION IS GIVEN TO THE PROCESSED GAS VOLUMES SUBSEQUENTLY DELIVERED TO THE FIELD STRADDLE PLANT.



OAS Reporting for Royalty Assessment Method 4a.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Production	IN-NET Facility A	GAS	PROC**	Any	royalty charge	Loc. Fac.

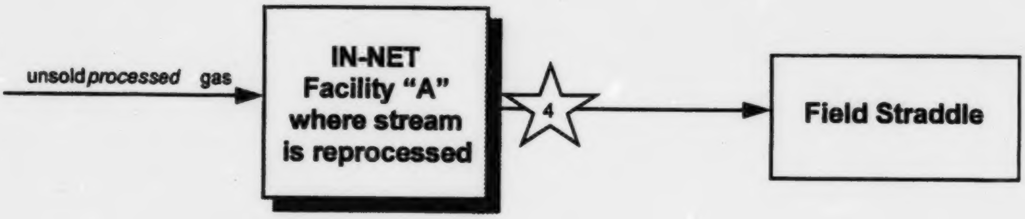
* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** *Gas dispositions at gathering systems are to be reported on the OAS as either a "Sale" or a "Transfer". There should be no "Process" activity reported at Location "BT" or "GS" for product GAS. If this is reported, royalty will be charged.*

4b. For previously unsold *processed* gas at a facility (excluding straddle and fractionation plants) where the stream is *further processed* and then delivered to a Field Straddle Plant, stream royalty assessable volume equals:

volumes processed

NOTE: NO ROYALTY REDUCTION IS GIVEN TO THE PROCESSED GAS VOLUMES DELIVERED TO THEFIELD STRADDLE PLANT.



OAS Reporting for Royalty Assessment Method 4b.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	PROC**	Any	royalty charge	Loc. Fac.

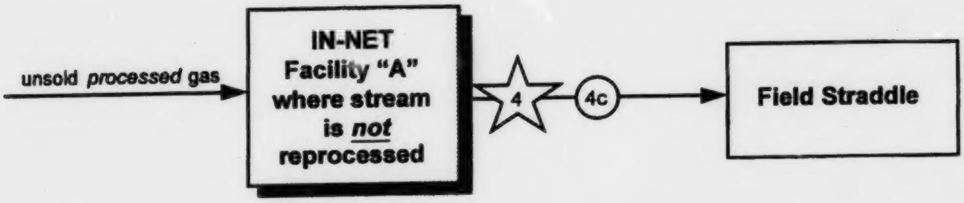
* *IS which is a Department-approved "Production-Motivated" Injection Scheme only.*

** Gas dispositions at gathering systems are to be reported on the OAS as either a "Sale" or a "Transfer". There should be no "Process" activity reported at Location "BT" or "GS" for product GAS. If this is reported, royalty will be charged.

4c. For previously unsold *processed* gas at a facility (excluding straddle and fractionation plants) where the stream is *not further processed* and is then delivered to a Field Straddle Plant, stream royalty assessable volume equals:

volumes received
...minus...
fuel consumed
...minus...
volumes flared
...minus...
metering difference (includes volumes vented and inventory adjustments)

NOTE: NO ROYALTY REDUCTION IS GIVEN TO THE PROCESSED GAS VOLUMES SUBSEQUENTLY DELIVERED TO THE FIELD STRADDLE PLANT.



OAS Reporting for Royalty Assessment Method 4c.

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Gas	IN-NET Facility Prior to A	GAS	TSF	IN-NET Facility A	royalty charge**	Dest. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	Fuel	Any	royalty reduction**	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	FLARE	Any	royalty reduction**	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	Meter	Any	royalty reduction**	Loc. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme.*

** *Only applicable if the same product stream is not further processed at the assessment facility.*

6.5 Royalty (Injection Credit) Trigger #5 - Facility Injection Credits

Facility where product received will be:

- injected into a production-motivated scheme (including cycling schemes); *and*
- consumed during the process of injecting product(s) into a production motivated injection scheme; *but*
- excludes approved storage schemes.

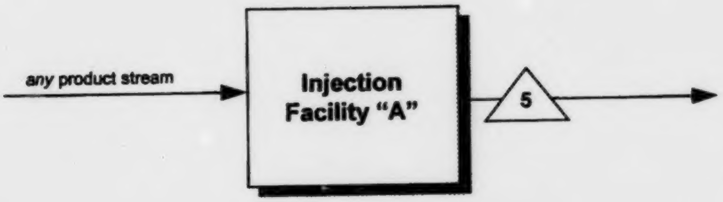
Royalty Assessment Method for Royalty Trigger #5

For any stream received at facility (excluding straddle and fractionation plants) for the purpose of injection, stream injection credit volume equals:

volumes received for injection purposes

NOTE: Volumes received for injection purposes are volumes received at the injection facility, which are either injected or consumed during the process of injecting gas and gas products into a production-motivated injection scheme. This excludes any subsequent delivery of volumes from the injection facility.

Volumes received may also be reported on the OAS as a Purchase Activity if the injection stream is purchased for injection purpose. The purchased volumes will be entitled to receive an injection credit. Subsequent reproduction of these volumes will be treated as native to the reservoir and subject to Crown royalty.



OAS Reporting for Royalty Assessment Method 5

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Injection	Any	Any	TSF	AB-IF	injection credit	Dest. Fac.
AB-WI/WG/UN/IS*	Injection	Any	Any	PURCH**	AB-IF	injection credit	Dest. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme.*

** *Reflects the purchasing of an injection stream for injection purpose.*

6.6 Royalty (Other Royalty Reduction) Trigger #6 — Facility Eligible Consumption

Facility where unsold, processed gas subject to royalty is used for fuel.

Royalty Assessment Method for Royalty Trigger #6

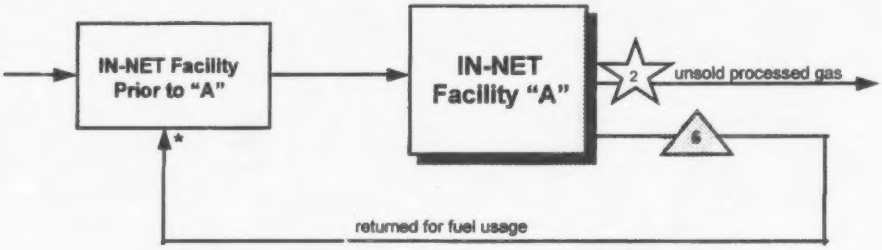
For previously unsold, *processed* gas that is returned to a facility (excluding straddle and fractionation plants) where the stream is consumed as fuel and consumption is eligible for royalty waiver *(refer to Section 5.2 for eligibility rules)*, stream royalty reduction volume equals:

volumes delivered to facility for fuel consumption

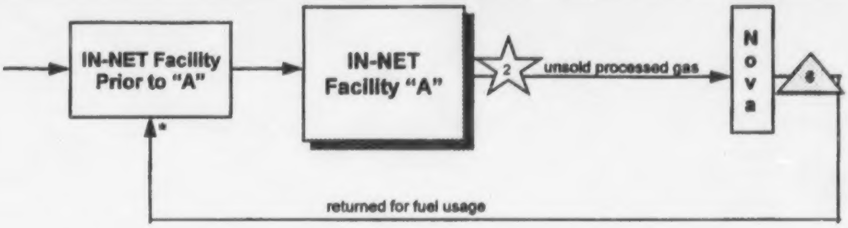
A royalty reduction will be given for these volumes. If the product stream is not reprocessed at the facility where it is returned for fuel consumption, a royalty liability will be assessed at the facility where the product stream is returned (see Royalty Assessment Method 2d.). To cancel this liability, operators must report the fuel which is consumed at that facility on the OAS.

NOTE: IN SOME CIRCUMSTANCES OF ELIGIBLE FUEL CONSUMPTION, PROCESSED GAS VOLUMES ARE DELIVERED TO A TRANSPORTATION FACILITY FIRST AND SUBSEQUENTLY RETURNED TO A FACILITY LOCATION TO BE CONSUMED AS FUEL AT THAT LOCATION. THE OAS REPORTING RULES ARE:

1. REPORT THE PRODUCT STREAM DELIVERED TO THE TRANSPORTATION FACILITY AS OAS "TRANSFER" ACTIVITY WITH DESTINATION TYPE "PL". DIFFERENTIATE OTHER PROCESSED GAS DELIVERED TO THE TRANSPORTATION FACILITY AND NOT RETURNED FOR ELIGIBLE FUEL CONSUMPTION AS A "SALE" ACTIVITY.
2. REPORT THE SUBSEQUENT RETURN OF THE PRODUCT STREAM FROM THE TRANSPORTATION FACILITY AS OAS "TRANSFER" ACTIVITY WITH LOCATION TYPE "PL" TO THE FACILITY WHERE THE FUEL CONSUMPTION TAKES PLACE.
3. REPORT THE VOLUMES CONSUMED AS FUEL AT THE LOCATION FACILITY WHERE CONSUMPTION TOOK PLACE IF THERE IS NO REPROCESSING OF PRODUCT STREAM AT THE LOCATION FACILITY.



* *At Facility "Prior to A" where stream is returned for fuel usage, stream will be subject to Royalty Trigger #2 (Royalty Assessment 2D).*



** At Facility "Prior to A" where stream is returned for fuel usage, stream will be subject to Royalty Trigger #2 (Royalty Assessment 2D).*

OAS Reporting for Royalty Assessment Method 6

Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessment Facility
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility Prior to A (for fuel usage)	royalty reduction	Loc. Fac.
AB- WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	IN-NET Facility Prior to A (for fuel usage)	royalty charge**	Dest. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	AB-PL	royalty reduction***	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility A	GAS	TSF	AB-PL	royalty charge***	Dest. Fac.
AB-WI/WG/UN/IS*	Gas	AB-PL	GAS	TSF	IN-NET Facility Prior to A (for fuel usage)	royalty reduction	Loc. Fac.
AB-WI/WG/UN/IS*	Gas	AB-PL	GAS	TSF	IN-NET Facility Prior to A (for fuel usage)	royalty charge**	Dest. Fac.
AB-WI/WG/UN/IS*	Gas	IN-NET Facility Prior to A	GAS	FUEL	Any	royalty reduction**	Loc. Fac.

* *IS which is a Department-approved "Production-Motivated" Injection Scheme.*

** *Only applicable if the same product stream is not further processed at the assessment facility.*

*** *Applicable when the processed gas stream is delivered to a transportation facility first and subsequently returns to a facility location to be consumed as fuel.*

7. Department-OAS Royalty Trigger Summary

Txn #	Stream ID Prov-Type[1]	Stream Category	Location Prov-Type[2]	Product	Activity	Destination Prov-Type	Action[3]	Assessm't Facility	Assessm't Method
1	AB-WI/WG/UN/IS	Production	"IN-NET"	Gas	EXCH (quantity < 0)	Any	RC	Loc. Fac.	2A
2	AB-WI/WG/UN/IS	Production	AB-GP (field straddle)	Gas	EXCH (quantity < 0)	Any	RC	Loc. Fac.	3A
3	AB-WI/WG/UN/IS	Production	"IN-NET"	Any	PROC	Any	RC	Loc. Fac.	1, 2B, 4A
4	AB-WI/WG/UN/IS	Production	AB-GP (field straddle)	Any	PROC	Any	RC	Loc. Fac.	3B, 3C

(The notes 1 to 6 that follow do not refer to the Txn numbers nor to the Assessment Method numbers, but to the other (note) numbers indicated in the tables under this section.)

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[1] *IS which is a Department-approved "Production-Motivated" Injection Scheme.*

[2] *IN-NET Facilities are facilities where OAS Province Code = AB, Type Code = BT/GS/GP, and where GP facility is a conventional gas processing plant.*

[3] *RC = Royalty Charge, RR = Royalty Reduction, IC = Injection Credit.*

Txn #	Stream ID Prov-Type	Stream Category	Location Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessm't Facility	Assessm't Method
5	AB-WI/WG/UN/IS	Production	"IN-NET"	Gas	SALE	Any[4]	RC	Loc. Fac.	2A
6	AB-WI/WG/UN/IS	Production	AB-GP (field straddle)	Gas	SALE	Any[4]	RC	Loc. Fac.	3A
7	AB-WI/WG/UN/IS	Production	"IN-NET"	Gas	TSF	"OUT-NET"[5]	RC	Loc. Fac.	2A
8	AB-WI/WG/UN/IS	Production	AB-GP (field straddle)	Gas	TSF	Any	RC	Loc. Fac.	3A
9	AB-WI/WG/UN/IS	Injection	Any	Any	TSF	AB-IF	IC	Dest. Fac.	5
10	AB-WI/WG/UN/IS	Injection	Any	Any	PURCH	AB-IF	IC	Dest. Fac.	5

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[4] *Royalty volumes valued at 80% Reference Price for Reference Price Filers if OAS Destination Type = GP, or OAS Destination = designated 80% valuation facilities per Department records*

[5] *OUT-NET Facilities are facilities where OAS Province code = AB, Type Code = IF/RF/TM/TF/PL/RR/TR/GP, and where GP facility is a mainline straddle or fractionation plant, or ex-Alberta facility locations.*

Txn #	Stream ID Prov-Type	Stream Category	ocation Prov-Type	Product	Activity	Destination Prov-Type	Action	Assessm't Facility	Assessm't Method
11	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	FUEL[6]	Any	RR	Loc. Fac.	2D, 4C, 6
12	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	FLARE[6]	Any	RR	Loc. Fac.	2D, 4C
13	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	METER[6]	Any	RR	Loc. Fac.	2D, 4C
14	B-WI/WG/UN/IS	Gas	"IN-NET"	Any	PROC	Any	RC	Loc. Fac.	1, 2C, 4B
15	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	TSF	"IN-NET"	RR	Loc. Fac.	2B, 2C, 2D, 6
*16	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	TSF	"IN-NET"	RC	Dest. Fac.	2B, 2C, 2D 6
* 17	B-WI/WG/UN/IS	Gas	AB-PL	Gas	TSF	"IN-NET"	RR	Loc. Fac.	6
18	B-WI/WG/UN/IS	Gas	AB-PL	Gas	TSF[6]	"IN-NET"	RC	Dest. Fac.	6
19	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	TSF	AB-PL	RR	Loc. Fac.	6
20	B-WI/WG/UN/IS	Gas	"IN-NET"	Gas	TSF	AB-PL	RC	Dest. Fac.	6

*** Revised**

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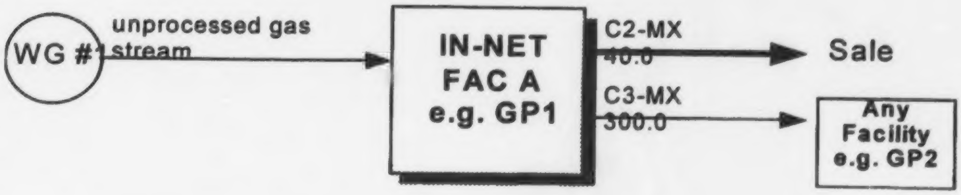
[6] *Only applicable if no processing of the product stream takes place at assessment facility.*

8. OAS Examples

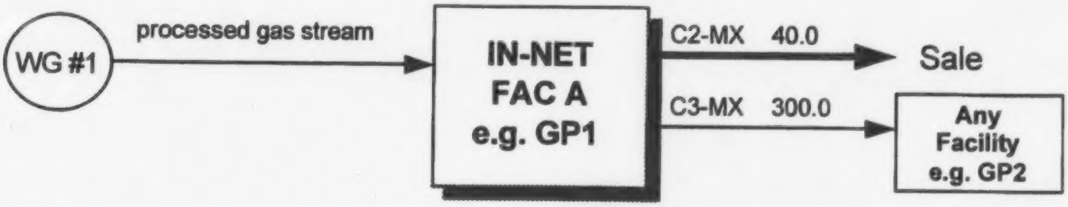
The following are OAS examples representing different business events. The purpose is to demonstrate how royalty is assessed based on the trigger details described in *Appendix B, Section 6.* The examples are not real OAS statements. In order to keep examples simple, a generic quantity has been used instead of showing gross and net numbers for quantity and heat.

A. Previously unsold, *unprocessed gas* stream *processed* at facility where *by-products* are extracted (Royalty Trigger Rule #1)


WG #1
unprocessed gas stream
IN-NET
FAC A
e.g. GP1
C2-MX
40.0
Sale
C3-MX
300.0
Any
Facility
e.g. GP2

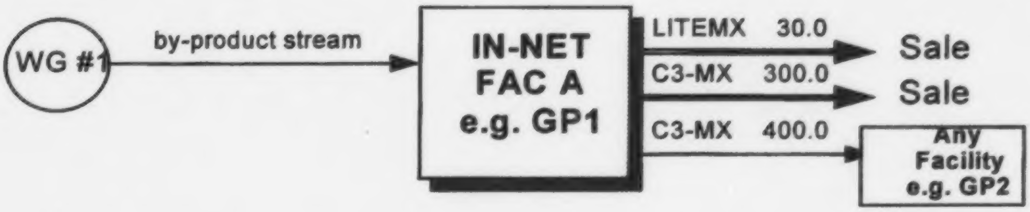
Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production	IN-NET Facility A	C2-MX	Proc	40.0	N/A	40.0	IN-NET Facility A
WG#1	Production	In-NET Facility A	C3-MX	Proc	300.0	N/A	300.0	IN-NET Facility A
WG#1	By-product	In-NET Facility A	C2-MX	Sale	40.0	Any		IN-NET Facility A
WG#1	By-product	-NET Facility	C3-MX	Tsf	300.0	Any		IN-NET Facility A

B. Previously unsold, *processed gas* stream *further processed* at facility where *by-products* are extracted (Royalty Trigger Rule #1)


WG #1
processed gas stream
IN-NET
FAC A
e.g. GP1
C2-MX 40.0
Sale
C3-MX 300.0
Any
Facility
e.g. GP2

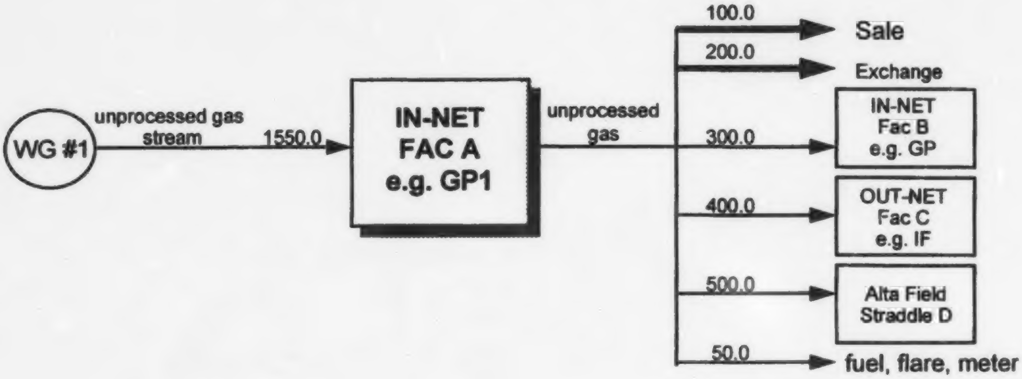
Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Gas	IN-NET Facility A	C2-MX	Proc	40.0	N/A	40.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	C3-MX	Proc	300.0	N/A	300.0	IN-NET Facility A
WG#1	By-product	IN-NET Facility A	C2-MX	Sale	40.0	Any		IN-NET Facility A
WG#1	By-product	IN-NET Facility A	C3-MX	Tsf	300.0	Any		IN-NET Facility A

C. Previously unsold, *by-product* stream processed at facility where additional *by-products* are extracted (Royalty Trigger Rule #1)



Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	By-product	IN-NET Facility A	LITEMX	Proc	30.0	N/A		
WG#1	By-product	IN-NET Facility A	C2-MX	Proc	300.0	N/A		
WG#1	By-product	IN-NET Facility A	C3-MX	Proc	400.0	N/A		
WG#1	By-product	IN-NET Facility A	LITEMX	Sale	30.0	Any		
WG#1	By-product	IN-NET Facility A	C2-MX	Sale	300.0	Any		
WG#1	By-product	IN-NET Facility A	C3-MX	Tsf	400.0	Any		

D. Previously unsold, *unprocessed gas sale/exchange/delivery prior to processing* at facility (Royalty Trigger Rule #2)


WG #1
unprocessed gas stream
1550.0
IN-NET FAC A e.g. GP1
unprocessed gas
100.0
Sale
200.0
Exchange
300.0
IN-NET Fac B e.g. GP
400.0
OUT-NET Fac C e.g. IF
500.0
Alta Field Straddle D
50.0
fuel, flare, meter

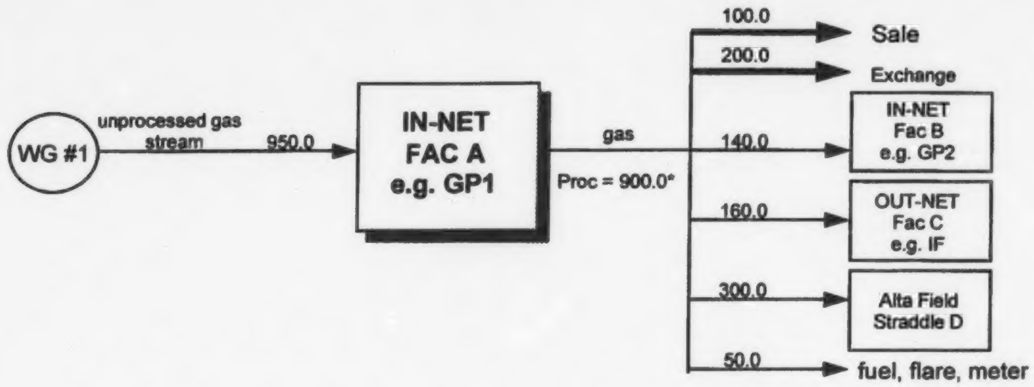
Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production	IN-NET Facility A	GAS	Sale	100.0*	Any**	100.0	IN-NET Facility A
WG#1	Production	IN-NET Facility A	GAS	Exch	-200.0*	Any	200.0	IN-NET Facility A
WG#1	Production	IN-NET Facility A	GAS	Tsf	300.0*	IN-NET Facility B		
WG#1	Production	IN-NET Facility A	GAS	Tsf	400.0*	OUT-NET Facility C	400.0	IN-NET Facility A
WG#1	Production	IN-NET Facility A	GAS	Tsf	500.0***	Alta.Field Straddle D		
WG#1	Production	IN-NET Facility A	GAS	Fuel/ Flare/ Meter	50.0	N/A		

* *Quantity is net of the 50.0 plant fuel, flare, meter.*

** *If Destination type is GP or Destination is one of the designated 80% valuation facilities per Department records, royalty volumes will be valued at 80% of Reference Price for Reference Price Filers. (Refer to Section 6.2.).*

*** *No royalty charge at Facility A as gas is delivered unprocessed to a Field Straddle Plant. Royalty will be charged at the Field Straddle Plant.*

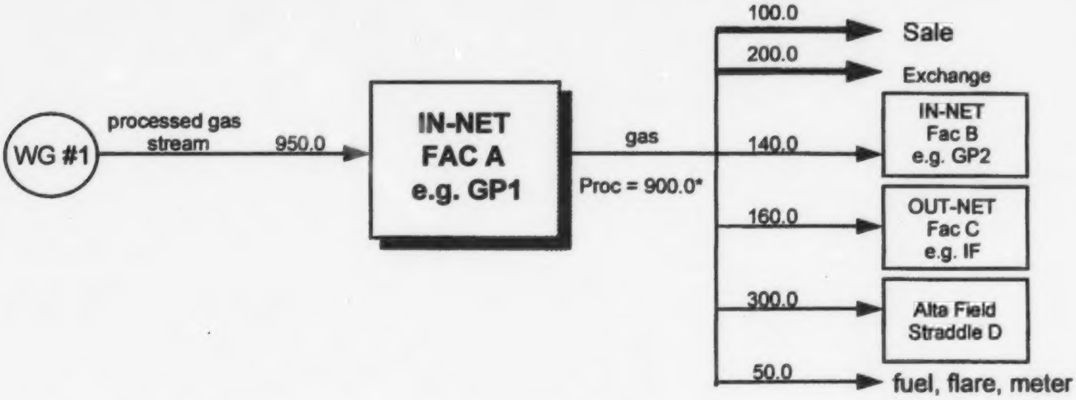
E. Previously unsold, *unprocessed gas processed* at facility (Royalty Trigger Rule #2)


WG #1
unprocessed gas stream
950.0
IN-NET
FAC A
e.g. GP1
gas
Proc = 900.0*
100.0
Sale
200.0
Exchange
140.0
IN-NET
Fac B
e.g. GP2
160.0
OUT-NET
Fac C
e.g. IF
300.0
Alta Field
Straddle D
50.0
fuel, flare, meter

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production	IN-NET Facility A	GAS	Proc	900.0*	N/A	900.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Sale	100.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Exch	-200.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	140.0	IN-NET Facility B	(140.0)	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Tsf	160.0	OUT-NET Facility C		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	300.0	Alta.Field Straddle D		
WG#1	Gas	IN-NET Facility A	GAS	Fuel/Flare/ Meter	50.0	N/A		

* *Quantity is net of the 50.0 plant fuel, flare meter.*

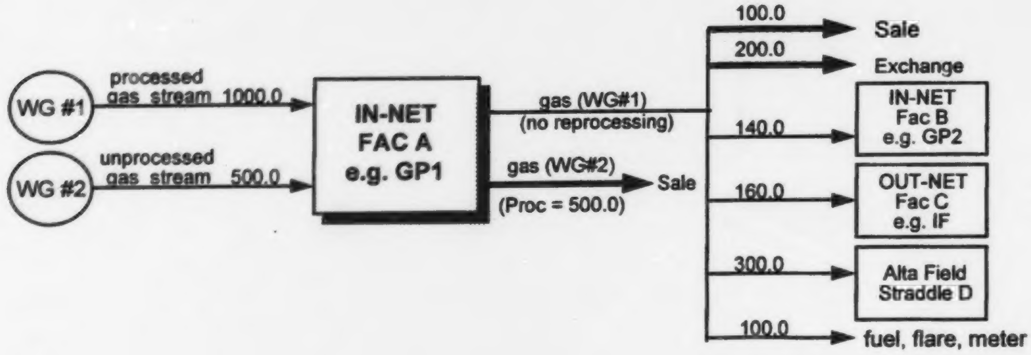
F. Previously unsold, *processed gas further processed* at facility (Royalty Trigger Rule #2)


WG #1
processed gas stream
950.0
IN-NET FAC A e.g. GP1
gas
Proc = 900.0*
100.0
Sale
200.0
Exchange
140.0
IN-NET Fac B e.g. GP2
160.0
OUT-NET Fac C e.g. IF
300.0
Alta Field Straddle D
50.0
fuel, flare, meter

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Gas	IN-NET Facility A	GAS	Proc	900.0*	Any	900.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Sale	100.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Exch	-200.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	140.0	IN-NET Facility B	(140.0)	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Tsf	160.0	OUT-NET Facility C		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	300.0	Alta.Field Straddle D		
WG#1	Gas	IN-NET Facility A	GAS	Fuel/ Flare/ Meter	50.0	N/A		

* *Quantity is net of the 50.0 plant fuel, flare, meter.*

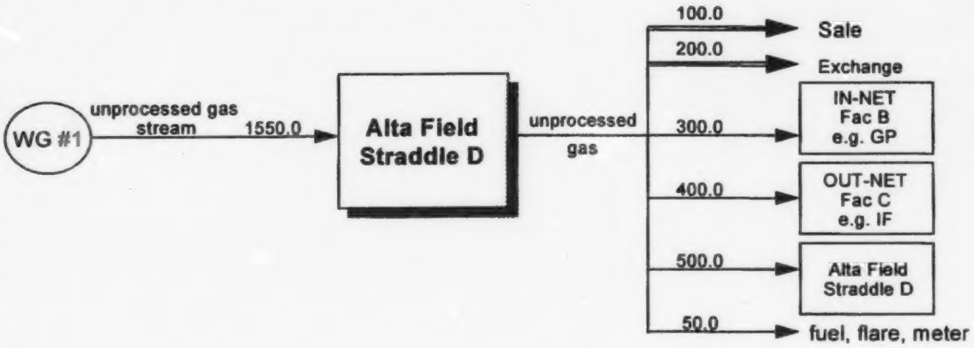
G. Previously unsold, *processed gas flow-through at facility without further processing* (Royalty Trigger R #2)


WG #1
processed gas stream 1000.0
WG #2
unprocessed gas stream 500.0
IN-NET FAC A e.g. GP1
gas (WG#1) (no reprocessing)
gas (WG#2)
(Proc = 500.0)
Sale
100.0
Sale
200.0
Exchange
140.0
IN-NET Fac B e.g. GP2
160.0
OUT-NET Fac C e.g. IF
300.0
Alta Field Straddle D
100.0
fuel, flare, meter

tream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Gas	IN-NET Facility Prior to A	GAS	Tsf	1000.0	IN-NET Facility A	1000.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Sale	100.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Exch	-200.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	140.0	IN-NET Facility B	(140.0)	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Tsf	160.0	OUT-NET Facility C		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	300.0	Alta.Field Straddle D		
WG#1	Gas	IN-NET Facility A	GAS	Fuel/Flare/ Meter	100.0	N/A	(100.0)	IN-NET Facility A
WG#2*	Production	IN-NET Facility A	GAS	Proc	500.0	N/A	500.0	IN-NET Facility A
WG#2	Gas	IN-NET Facility A	GAS	Sale	500.0	Any		

* *WG#2 is shown here to demonstrate another stream being processed at the facility which is not related to the flow-through stream.*

H. Previously unsold, *unprocessed gas* at Field Straddle Plant where there is *sale/exchange/delivery of stream prior to processing at the field straddle plant* (Royalty Trigger Rule #3)

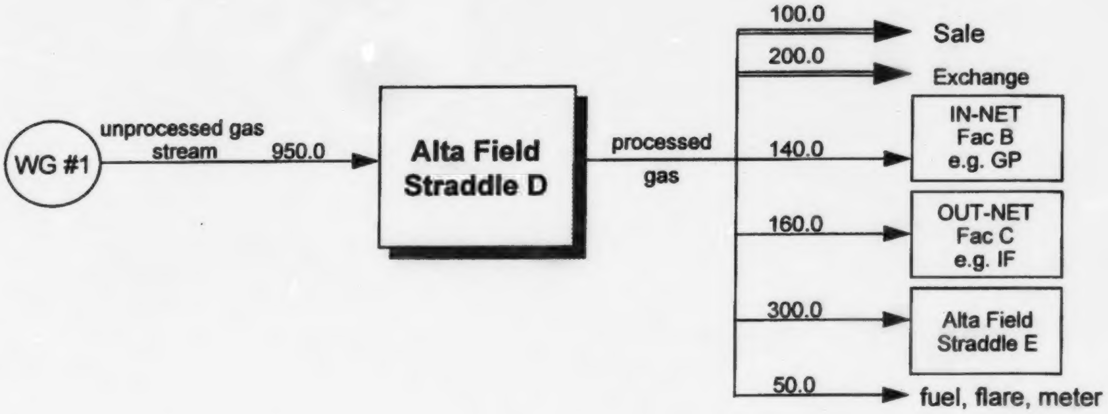

WG #1
unprocessed gas stream
1550.0
Alta Field Straddle D
unprocessed gas
100.0
Sale
200.0
Exchange
300.0
IN-NET Fac B e.g. GP
400.0
OUT-NET Fac C e.g. IF
500.0
Alta Field Straddle D
50.0
fuel, flare, meter

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production	Alta. Field Straddle D	GAS	Sale	100.0*	Any**	100.0	Alta. Field Straddle D
WG#1	Production	Alta. Field Straddle D	GAS	Exch	-200.0*	Any	200.0	Alta. Field Straddle D
WG#1	Production	Alta. Field Straddle D	GAS	Tsf	300.0*	IN-NET Facility B	300.0	Alta. Field Straddle D
WG#1	Production	Alta. Field Straddle D	GAS	Tsf	400.0*	OUT-NET Facility C	400.0	Alta. Field Straddle D
WG#1	Production	Alta. Field Straddle D	GAS	Tsf	500.0*	Alta. Field Straddle E	500.0	Alta. Field Straddle D
WG#1	Production	Alta. Field Straddle	GAS	Fuel/ Flare/ Meter	50.0	N/A		

* *Quantity is net of the 50.0 plant fuel, flare, meter.*

** *If Destination type is GP, or Destination is one of the designated 80% valuation facilities per Department records, royalty volumes will be valued at 80% of Reference Price for Reference Price Filers*

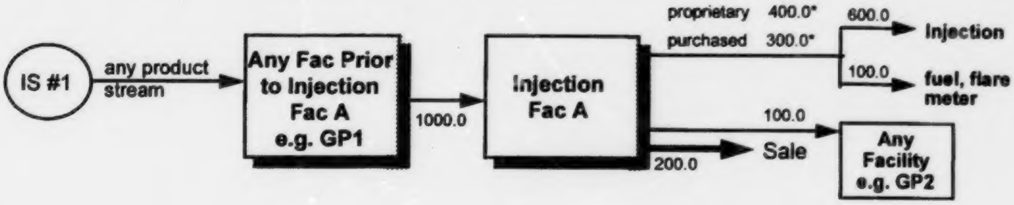
I. Previously unsold, *unprocessed gas* at Field Straddle Plant where stream is *processed at the field straddle plant* (Royalty Trigger Rule #3)


WG #1
unprocessed gas stream
950.0
Alta Field Straddle D
processed gas
100.0
Sale
200.0
Exchange
140.0
IN-NET Fac B e.g. GP
160.0
OUT-NET Fac C e.g. IF
300.0
Alta Field Straddle E
50.0
fuel, flare, meter

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production	Alta. Field Straddle D	Any	Proc	900.0*	Any	900.0	Alta. Field Straddle D
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Sale	100.0	Any		
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Exch	-200.0	Any		
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Tsf	140.0	IN-NET Facility B		
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Tsf	160.0	OUT-NET Facility C		
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Tsf	300.0	Alta. Field Straddle E		
WG#1	Gas/ By-product	Alta. Field Straddle D	Any	Fuel/Flare/ Meter	50.0	N/A		

* *Quantity is net of the 50.0 plant fuel, flare, meter.*

J. Injection Credit Trigger (Royalty Trigger Rule #5)

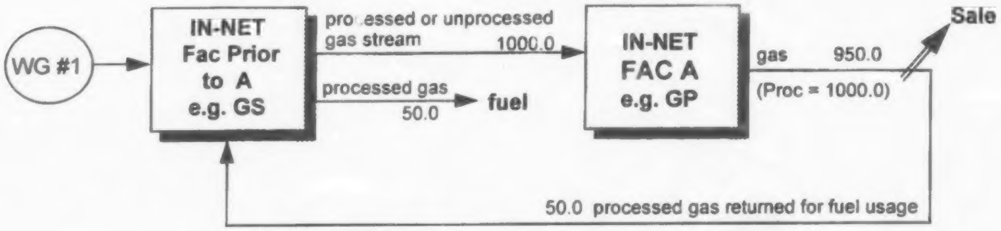

IS #1
any product stream
Any Fac Prior to Injection Fac A e.g. GP1
1000.0
Injection Fac A
proprietary 400.0*
purchased 300.0*
600.0
Injection
100.0
fuel, flare meter
100.0
Any Facility e.g. GP2
200.0
Sale

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
IS#1	Injection	Any	Any	Tsf	400.0*	AB-IF A	(400.0)	AB-IF A
IS#1	Injection	Any	Any	Purch**	300.0*	AB-IF A	(300.0)	AB-IF A
IS#1	Injection	AB-IF A	Any	Injection	600.0	N/A		
IS#1	Injection	AB-IF A	Any	Fuel	100.0	N/A		
IS#1	Production/ Gas/ By-product	AB-IF A	Any	Tsf	100.0	Any		
IS#1	Production/ Gas/ By-product	AB-IF A	Any	Sale	200.0	Any		

* *Quantities eligible for injection credit should reflect the volumes injected and volumes consumed during the process of injecting product(s) into a production-motivated injection scheme, they exclude any subsequent sale/delivery of volumes from the injection facility.*

** *Reflects the purchasing of an injection stream for injection purpose.*

K. Eligible Fuel Consumption, *Royalty Waived Volume Returned to Upstream Facility for Fuel Consumpti*
(Royalty Trigger Rule #6)


WG #1
IN-NET Fac Prior to A e.g. GS
processed or unprocessed gas stream 1000.0
processed gas 50.0
fuel
IN-NET FAC A e.g. GP
gas 950.0
(Proc = 1000.0)
Sale
50.0 processed gas returned for fuel usage

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production/ Gas	IN-NET Facility A	GAS	Proc	1000.0	N/A	1000.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Sale	950.0	Any		
WG#1	Gas	IN-NET Facility A	GAS	Tsf	50.0*	IN-NET Facility Prior to A (for fuel usage)	(50.0)	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Tsf	50.0	IN-NET Facility Prior to A (for fuel usage)	50.0** Note 1	IN-NET Facility Prior to A
WG#1	Gas	IN-NET Facility Prior to A	GAS	Fuel***	50.0	N/A	(50.0) Note 1	IN-NET Facility Prior to A

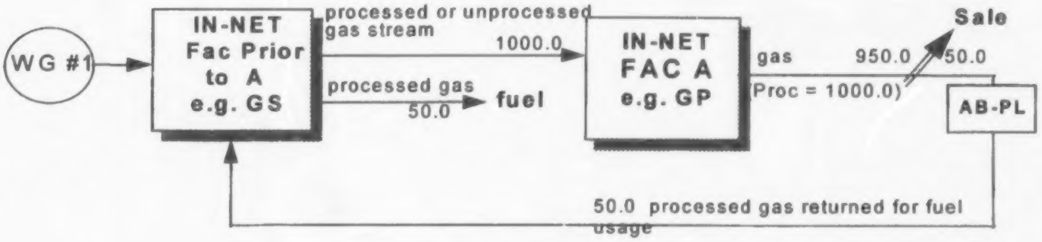
* *Volumes returned to a facility for fuel consumption which is eligible for royalty waiver.*

** *Only applicable if no further processing of same product stream takes place at destination facility.*

*** *Returned volumes consumed as fuel must be reported if stream is not reprocessed, otherwise volumes will be subject to royalty per Royalty Assessment Method 2D.*

NOTE: WHEN PROCESSED GAS IS RETURNED TO THE UPSTREAM FACILITY SOLELY FOR FUEL USAGE, IT WILL FIRST GENERATE A ROYALTY CHARGE AT THE UPSTREAM FACILITY. THIS CHARGE WILL BE OFFSET BY REPORTING TH VOLUMES AS CONSUMED FOR FUEL USAGE AT THE UPSTREAM FACILITY.

L. Eligible Fuel Consumption, *Royalty Waived Volumes Delivered to Pipeline and Subsequently Returned to Upstream Facility for Fuel Consumption* (Royalty Trigger Rule #6)


WG #1
IN-NET Fac Prior to A e.g. GS
processed or unprocessed gas stream
1000.0
processed gas
50.0
fuel
IN-NET FAC A e.g. GP
gas
950.0
Sale
50.0
(Proc = 1000.0)
AB-PL
50.0 processed gas returned for fuel usage

Stream ID	Category	Location	Product	Activity	Quantity	Dest'n	Royalty (Credit)	Assessm't Facility
WG#1	Production/ Gas	IN-NET Facility A	GAS	Proc	1000.0	N/A	1000.0	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Sale	950.0	Any		
WG#1	Gas	IN-Net Facility A	GAS	Tsf	50.0	AB-PL*	(50.0)	IN-NET Facility A
WG#1	Gas	IN-NET Facility A	GAS	Tsf	50.0	AB-PL	50.0	AB-PL
WG#1	Gas	AB-PL	GAS	Tsf**	50.0	IN-NET Facility Prior to A (for fuel usage)	(50.0)	AB-PL
WG#1	Gas	AB-PL	GAS	Tsf***	50.0	IN-NET Facility Prior to A (for fuel usage)	50.0*** Note 1	IN-NET Facility Prior to A
WG#1	Gas	IN-NET Facility Prior to A	GAS	Fuel***	50.0	N/A	(50.0)*** Note 1	IN-NET Facility Prior to A

* *Volumes delivered to pipeline and subsequently returned to a facility for fuel consumption which are eligib for royalty waiver.*

** *Volumes returned from pipeline to facility where volumes for fuel consumption as well as the volumes consumed as fuel must be reported; otherwise, volumes will be subject to royalty per Royalty Assessment Methods 2D and 6.*

*** *Only applicable if the same product stream is not further processed at the assessment facility.*

NOTE: WHEN PROCESSED GAS IS RETURNED FROM THE PIPELINE BACK TO THE UPSTREAM FACILITY SOLELY FOR FUEL USAGE, IT WILL FIRST GENERATE A ROYALTY CHARGE AT THE UPSTREAM FACILITY. THIS CHARGE WILL BE OFFSET BY REPORTING THE VOLUMES AS CONSUMED FOR FUEL USAGE AT THE UPSTREAM FACILITY.

1. Validation Rules - Owner Activity Statement (OAS)

All OAS transmissions will be subject to the Data Element Rules as defined in PRIDE's Release 3 document. In addition, all OAS transmissions will be subject to the Department's OAS Validation Rules. Where the Department's OAS Validation Rules conflict with PRIDE's Data Element Rules, the Department's rules will prevail.

All OAS amendments must be full form replacements.

Listed below are validation rules that the Department has established to validate all OAS forms.

A. Edits Which Will Result in Rejecting the Entire OAS

1.1 Reject OAS with an invalid/inactive operator ID. (Invalid/inactive refers to an ID that does not exist on the MRIS **Business Associate*** registry or the ID exists but is inactive for the production period.) The normal error reporting method of generating an OAS Edit Rejection Notice cannot be used since the address (obtained using the operator ID which is invalid in this case) is unavailable. Operators using invalid Operator IDs, will be contacted by telephone and be asked to re-file the OAS.

1.2 Reject OAS if owner is an invalid/inactive Business Associate ID or Operator ID. (Invalid/inactive refers to an ID that does not exist on the MRIS Business Associate registry, or the ID exists but is inactive for the production period). Operator IDs should be reported as a four-digit code effective 1994-01, although MRIS will zero-fill three digit codes to four digits automatically.

1.3 Reject OAS with invalid or future production period and filing dates greater than current date.

1.4 Reject OAS if filing dates are less than or equal to the filing dates of previous submissions for the same operator, reporting facility, owner, and production period. (The client will be notified of previous submissions filing date.) If two OASs are received in one day bearing the same filing date, the second OAS will be rejected.

1.5 Reject OAS with invalid/inactive reporting (i.e., header) facilities. (Invalid/inactive refers to a facility that does not exist on the MRIS facility registry, or the facility exists but is inactive for the production period.) The Prov/Type/Code relationship of the facility will be validated. Refer to the PRIDE document for valid reporting facility type.

1.6 Reject OAS that does not include all header information required by the Department. (The required information is reporting facility code, operator code, owner code, production period, and filing date.)

B. Edits Which Will Result in an Inaction of the Entire OAS

1.7 If the allocator field is populated on the OAS (record type 23), the Department will ignore the OAS filed. No processing of the OAS data will be done. The allocator field is used for owner to owner reporting between Industry partners and is not recognized by the Department. Re-allocation of volumes to silent partners or other owners are only recognized by the Department via Royalty Responsibility Reassignment, RMF2 form.

****for definition, please see Appendix N - Glossary***

C. Edits Which Will Result in Rejecting the OAS Detail Line Record

1.8 Reject OAS record line if the Stream ID is invalid/inactive. (Invalid/inactive refers to a stream ID that does not exist on the MRIS Facility registry or the stream ID exists but is inactive for the production period.) The Prov/Type/Code relationship of the stream ID will be validated.

Refer to PRIDE document for valid stream ID types. In addition, OAS volumes are to be reported at the highest reporting entity level, that is, if a well is in a grouping-well group, unit, or injection scheme, it must be reported at that level instead of at the well event level. Holiday wells and wells approved under the Otherwise Flared Solution Gas Royalty Waiver Program (OSFG) are an exception to this reporting rule. All single wells, holiday wells and OFSG wells must be reported at the well event level on the OAS.

1.9 Reject OAS record line if Location is invalid/inactive. (Invalid/inactive refers to a location that does not exist on the MRIS Facility registry or the location exists but is inactive for the production period.) The Prov/Type/Code relationship of the location will be validated. Refer to PRIDE document for valid location types.

1.10 Reject OAS record line if Destination is invalid/inactive. (Invalid/inactive refers to a destinationthat does not exist on the MRIS Facility registry or the destination exists but is inactive for the production period.) If the destination type is BT/GS/GP/IF/PL, the Prov/Type/Code relationship of the destination will be validated. Otherwise, only the destination type will be validated. Refer to PRIDE document for valid destination types. In cases where destination reporting is not mandatory, the Department will still validate the field when it is reported on the OAS. (See PRIDE document for requirement standards.)

1.11 Reject OAS record line if Activity = 'Transfer' and Destination is blank.

1.12 Reject OAS record line if Product = 'NGL' or 'LPG', Activity = 'Process', and Stream Category = 'Production' or 'Gas'. In these cases, NGL/LPG must be reported under its mix components.

1.13 Reject OAS record line with negative net quantity or net heat content values except where Activity = 'Exchange', 'Metering Difference', 'Opening Inventory', or 'Closing Inventory'.

1.14 Reject OAS record line if heat content is blank, Product = 'Gas' and Net Quantity '>0' except where:

- Activity = 'Storage Withdrawal'; *or*
- Location Type = 'BT' or 'GS' or 'GP' and Stream Category = 'Production', 'Cascade', 'Purchase', 'Multi', 'Bank', or 'Storage'.

1.15 Reject OAS record line if net heat content is greater than '4.0' and the net quantity is blank. (Working assumption is 4.0 GJs = 0.1 e^3m^3.)

1.16 Reject OAS record line if Stream ID Type = 'BT', 'GS', 'GP', or 'IF', Stream Category = 'Cascade' and the OAS Owner is not the operator (per MRIS Facility registry) of the facility identified in the stream ID as of the production date.

1.17 Reject OAS record line if Stream ID Type = 'BT', 'GS', 'GP', or 'IF', Stream Category = 'Production' or 'Gas', and Activity = 'Process', 'Sale', or 'Transfer'.

1.18 Reject OAS record line if heat reported is unreasonable where product = gas.

An edit check will now be performed on all lines on an OAS in which gas is reported. If the heat factor (GJ's divided by 10^3m^3) is unreasonable, the following reject message will be displayed:

Unreasonable Heat Reported

This edit is a line reject, and will not reject the entire OAS.

This edit is intended to prevent royalties from being over (under) charged due to possible keying errors in recording the heat content of the gas stream.

1.19 OAS Validation Edit - 'Process' Activity at Gas Gathering Systems for Product 'GAS'

A new edit has been incorporated into the OAS validation process. Any OAS detail line with a "PROCESS" activity, location of Gas Gathering System (Facility type of 'GS') and product 'GAS' will be rejected with the following message:

> *INVALID PRODCT/ACTVTY/LOCATION*

This edit is effective August 15, 1998 and will retroactively revalidate all OAS' within the database. **Any OAS' detail lines previously accepted with the criteria mentioned above will now reject.**

This new edit is intended to reduce possible **overcharges** of crown royalty/provisional assessments to royalty clients, as an activity of 'process' at a gathering system is not incorporated into the Crown's S/OAS reconciliation, yet is a royalty trigger. Under the previous validation rules, the line would have been accepted, charged royalty, and may have been subject to Provisional Assessment.

Royalty clients are advised to review their reject letters and respective OAS forms to determine if the resulting activity should be "SALE" or "TRANSFER". **Where applicable, royalty clients must resubmit the corrected OAS documents where royalty has been reversed.**

VALIDATION RULES FOR AC2

AC2 FORM: ALLOWABLE COSTS – CAPITAL COST ALLOWANCE

PART 1: IDENTIFICATION

Fields to be completed		**Form edits**	***Results of incorrect field***
1.1	Province	- if not AB, BC, or SK	FORM REJECTED
	Facility type	- if not GP or GS	FORM REJECTED
	EUB facility code	- if the EUB facility is not tied to the facility cost centre (field 1.2) - invalid facility ID	FORM REJECTED FORM REJECTED
1.2 Facility cost centre code		- invalid facility - facility cost centre - if facility cost centre is ineffective for the entire production year to which the form relates - facility cost centre is "shut-in" (shut-in information stored with AC1).	FORM REJECTED FORM REJECTED FORM REJECTED
1.3 Description of facility cost centre code		- no edit checks (description is used from AC1)	
1.4 Facility cost centre operator ID		- invalid client ID - if client ID is not the operator at December 31 of the production year to which the form relates	FORM REJECTED FORM REJECTED
1.5 Facility cost centre operator name		- no edit checks	

AC2 FORM: ALLOWABLE COSTS – CAPITAL COST ALLOWANCE

PART 1: IDENTIFICATION

Fields to be completed	**Form edits**	***Results of incorrect field***
1.6 Production year	- if less than the 1994 production year	*FORM REJECTED*
	- if greater than the current production year	*FORM REJECTED*
	- if AC2-V1 is used for the production year greater than or equal to 1997	FORM REJECTED
	- if AC2-V2 is used for the production year less than 1997	FORM REJECTED
1.7 Date prepared	- invalid date	*FORM REJECTED*
	- if date prepared is less than the date prepared of the current version on file	FORM REJECTED
	- if greater than the current date	FORM REJECTED
1.8 Contact person	- no edit checks	*accept as entered*
1.9 Telephone	- no edit checks	*accept as entered*

PART 2: CAPITAL COST ALLOWANCE CALCULATION

2.1 Cumulative allowable capital Jan 1 or__	NEW FCC	
	-if value is less than zero	FORM REJECTED
	-if value is less than field 2.2	FORM REJECTED
	EXISTING FCC -no edit checks	*use* Calculated Value

AC2 FORM: ALLOWABLE COSTS – CAPITAL COST ALLOWANCE

PART 2: CAPITAL COST ALLOWANCE CALCULATION

Fields to be completed		**Form edits**	*Results of incorrect field*
2.2 Allowable capital cost Jan 1 or __		NEW FCC	
		- if value is less than zero	FORM REJECTED
		- if value is greater than field 2.1	FORM REJECTED
		EXISTING FCC	
		- no edit checks	*use* Calculated Value
2.3 Capital additions		NEW FCC	
		- no edit checks	Accept as entered
		EXISTING FCC	
		- if sum of (2.2 and actual 2.3) is less than zero	*use* Calculated value actual 2.3 equals negative value of 2.2
2.4 Cumulative allowable capital Dec 31 or __		- no edit checks	*use* Calculated Value
2.5 Allowable capital cost before depreciation Dec 31 or __		- no edit checks	*use* Calculated Value
2.6	Depreciation ($)	- no edit checks	*use* Calculated Value
	__/12	- compare 2.6, 2.14 and actual calculated value	*use* lesser of 2.6, 2.14 and calculated value

AC2 FORM: ALLOWABLE COST CAP

PART 2: CAPITAL COST ALLOWANCE CALCULATION

Fields to be completed		**Form edits**	***Results of incorrect field***
2.7	Allowable capital cost after depreciation Dec 31 or __	- no edit checks	*use* Calculated Value
2.8 Average capital		- no edit checks	*use* Calculated Value
2.9 Land		- if value is negative	*FORM REJECTED*
2.10 Average spare parts inventory		- if value is negative	*FORM REJECTED*
2.11 Total		- no edit checks	*use* Calculated Value
2.12 Retirements		- no edit checks	*use* Calculated Value
2.13 Depreciation		- no edit checks	*use* Calculated Value
2.14	return on average capital ($)	- no edit checks	*use* Calculated Value
	__/12	- compare 2.6, 2.14 and actual calculated value	*use* lesser of 2.6, 2.14 and calculated value
2.15 Capital cost allowance		- no edit checks	*use* Calculated Value

AC2 FORM: ALLOWABLE COST CAP

PART 3: CAPITAL ADDITIONS – optional

Fields to be completed	**Form edits**	***Results of Incorrect field***
3.1 Additions /disposition/ retirements	- no edit checks	*accept as entered*
3.2 Type	- if invalid type (valid type includes A, D and R) - if blank and corresponding 3.3 exists	*FORM REJECTED* FORM REJECTED
3.3 Amount	- no edit checks	*accept as entered*
3.4 Total	- all additions are treated as positive values - dispositions, retirements are treated as negative values	*use* Calculated Value
PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS		
4.1 Client ID	- invalid client ID - if client ID is ineffective within the facility centre effective date range - if client ID appears more than once in PART 4	*FORM REJECTED* FORM REJECTED FORM REJECTED
4.3 Capital cost allowance distributions %	- if value is less than zero or greater than 100 * *Under Review,* effective September 1998 zero percentages will not reject the entire form. **Note:** If your company has encountered a form reject due to this edit and subsequently received penalties, please submit a letter with supporting details and the rejection notice to the attention of Pat Van Meer.	*FORM REJECTED*

AC2 FORM: ALLOWABLE COST CAP

PART 3: CAPITAL ADDITIONS – optional

Fields to be completed	**Form edits**	***Results of incorrect field***
3.1 Additions /disposition/ retirements	- no edit checks	*accept as entered*
3.2 Type	- if invalid type (valid type includes A, D and R) - if blank and corresponding 3.3 exists	*FORM REJECTED* FORM REJECTED
3.3 Amount	- no edit checks	*accept as entered*
3.4 Total	- all additions are treated as positive values - dispositions, retirements are treated as negative values	*use* Calculated Value

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

4.1 Client ID	- invalid client ID - if client ID is ineffective within the facility centre effective date range - if client ID appears more than once in PART 4	*FORM REJECTED* FORM REJECTED FORM REJECTED
4.3 Capital cost allowance distributions %	- if value is less than zero or greater than 100 * *Under Review,* effective September 1998 zero percentages will not reject the entire form. **Note:** If your company has encountered a form reject due to this edit and subsequently received penalties, please submit a letter with supporting details and the rejection notice to the attention of Pat Van Meer.	*FORM REJECTED*

AC2 FORM: ALLOWABLE COSTS – CAPITAL COST ALLOWANCE

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

Fields to be completed		**Form edits**	***Results of incorrect field***
4.5	**(1997+ AC2-V2 only)** total capital cost allowance allocated	- if total of all the 4.3 allocations and 5.7 (calculated value) is not equal 100% **Due to 5.7 calculated value:** If your company has encountered a form reject due to this edit and subsequently received penalties, please submit a letter with supporting details and the rejection notice to the attention of Pat Van Meer	*FORM REJECTED*

PART 5: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

5.1 Client ID	- *invalid client ID*	*FORM REJECTED*
	- if client ID is ineffective within the facility cost centre effective date range	FORM REJECTED
	- if blank and corresponding 5.3 and 5.4 exist	FORM REJECTED
	- if client ID appears more than once in PART 5	FORM REJECTED
5.2 Client name	- *no edit checks*	
5.3 Unit	- *if more than one unit flag box is checked* - if no unit flag box is checked	*FORM REJECTED*
5.4 Custom Volumes	- if blank and corresponding 5.1 and 5.3 exist	*FORM REJECTED*

AC2 FORM: ALLOWABLE COSTS – CAPITAL COST ALLOWANCE

PART 5: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

Fields to be completed	**Form edits**	***Results of Incorrect field***
5.5 Total custom volumes	*- no edit checks*	*use* calculated value
5.6 Total facility cost centre throughput	*- if blank or less than zero and 5.5 is greater than zero*	*FORM REJECTED*
5.7 Custom processing adjustment factor %	*- if blank*	*FORM REJECTED*
	- if value is not numeric	FORM REJECTED
	- if less than zero or greater than 100	FORM REJECTED
	- if above edits pass this calculated value is used to replace 4.4 (*Under Review* for rounding tolerance, effective September 1998.	use *Calculated Value*

AC3 FORM: CAPITAL COSTS ALLOWANCE REALLOCATIONS

PART 1: IDENTIFICATION

Fields to be completed		***Form Edits***	***Results of incorrect field***
1.1	Province	- if not AB, BC, or SK	FORM REJECTED
	Facility type	- if not GP or GS	FORM REJECTED
	EUB facility code	- if the EUB facility is not tied to the Facility Cost Centre (field 1.2)	FORM REJECTED
		- invalid facility ID	FORM REJECTED
1.2	Facility cost centre code	- invalid facility cost centre	FORM REJECTED
		- if facility cost centre is ineffective for the entire production year to which the form relates	FORM REJECTED
		- facility cost centre is "shut-in" (shut-in information stored with AC1)	FORM REJECTED
1.3	Description of facility cost centre code	- no edit checks (description is used from AC1)	
1.4	Client ID	- invalid client ID	FORM REJECTED
		- if client has not been allocated capital costs via an AC2 filed by another client for the facility cost centre and production year to which the form relates	FORM REJECTED FORM REJECTED
1.5	Client name	- no edit checks	
1.6	Production year	- if less than the 1994 production year	FORM REJECTED
		- if greater than the current production year	FORM REJECTED

F5

AC3 FORM: CAPITAL COSTS ALLOWANCE REALLOCATIONS

PART 1: IDENTIFICATION

Fields to be completed	***Form Edits***	***Results of incorrect field***
1.7 Date prepared	- invalid date	FORM REJECTED
	- if date prepared is less than the date prepared of the current version on file	FORM REJECTED
	- if greater than current date	FORM REJECTED
1.8 Contact person	- no edit checks	accept as entered
1.9 Telephone	- no edit checks	accept as entered
PART 2: CAPITAL COST ALLOWANCE REALLOCATIONS		
2.1 Client ID	- invalid client ID	FORM REJECTED
	- if client ID is ineffective for the entire production year to which the form relates	FORM REJECTED
	- if blank and corresponding 2.3 exists	FORM REJECTED
2.2 Client Name	- no edit checks	
2.3 Percentage of original allocation	- if greater than	FORM REJECTED
	- if blank and corresponding 2.1 exists	FORM REJECTED
	- sum of all 2.3 allocations is greater than 100%	FORM REJECTED
	- client ID appears more than once in PART 2	FORM REJECTED

Form Edits

AC4 FORM: ALLOWABLE COSTS OPERATING COSTS

PART 1: IDENTIFICATION

Fields to be completed		Form edits	Results of incorrect field
1.1	Province	- if not AB, BC or SK	FORM REJECTED
	Facility type	- if not GP or GS	FORM REJECTED
	EUB facility code	- if EUB facility code is not tied to the Facility Cost Centre registry (field 1.2)	FORM REJECTED
		- EUB facility is not a designated facility	FORM REJECTED
		- reported facility is a special facility code for the production year 1998 and onwards	FORM REJECTED
		Note: Special Cases Facilities were dismantled effective the 1998 production year	
		- invalid facility ID	FORM REJECTED
1.2	Facility cost centre code	- invalid facility cost centre	FORM REJECTED
		- if facility cost centre is ineffective for the entire production year to which the form relates	FORM REJECTED
		- facility cost centre is "shut-in" (shut-in information stored with AC1)	FORM REJECTED
1.3	Description of facility cost centre	- no edit checks (description is used from AC1)	
1.4	Facility cost centre operator ID	- invalid client ID	FORM REJECTED
		- if client ID is not the operator at December 31 of production year to which the form relates	FORM REJECTED
1.5	Facility cost centre operator name	- no edit checks	
1.6	Production year	- if less than 1994 production year	FORM REJECTED
		- if greater than current production year	FORM REJECTED

AC4 FORM: ALLOWABLE COSTS OPERATING COSTS		
PART 1: IDENTIFICATION		
Fields to be complete	**Form edits**	***Results of incorrect field***
1.7 Date prepared	- invalid date - if date prepared is less than the date prepared of the current version on file - if greater than the current date	FORM REJECTED FORM REJECTED FORM REJECTED
1.8 Contact person	- no edit checks	accept as entered
1.9 Telephone	- no edit checks	accept as entered
PART 2: ALLOWABLE OPERATING COSTS		
2.1 Labour	- if value is negative - if 0.0	FORM REJECTED accept as entered
Materials	- if value is negative - if 0.0	FORM REJECTED accept as entered
Chemicals	- if value is negative - if 0.0	FORM REJECTED accept as entered
Transportation	- if value is negative - if 0.0	FORM REJECTED accept as entered
Contract services	- if value is negative - if 0.0	FORM REJECTED accept as entered
Utilities	- if value is negative - if 0.0	FORM REJECTED accept as entered
Maintenance	- if value is negative - if 0.0	FORM REJECTED accept as entered
Automotive	- if value is negative - if 0.0	FORM REJECTED accept as entered

AC4 FORM: ALLOWABLE COSTS OPERATING COSTS

PART 2: ALLOWABLE OPERATING COSTS

Fields to be complete		**Form edits**	***Results of Incorrect field***
2.1	Insurance	- if value is negative - if 0.0	FORM REJECTED accept as entered
	Property taxes	- if value is negative - if 0.0	FORM REJECTED accept as entered
	Surface rentals	- if value is negative - if 0.0	FORM REJECTED accept as entered
2.2	Other allowables (description)	- no edit checks	accept as entered
2.3	Other allowables (actual operating costs)	- no edit checks **Note:** all negative values will be subject to audit review	
2.4	Direct allowable operating costs	- no edit checks	use *Calculated Value*
2.5	Overhead ____%	- no edit checks	use *Calculated Value*
2.6	Direct allowable operating costs & overhead	- no edit checks	use *Calculated Value*
2.7	Working capital allowance	- no edit checks	use *Calculated Value*
2.8	Total allowable operating costs	- no edit checks	use *Calculated Value*

AC5 FORM: ALLOWABLE COSTS CUSTOM PROCESSING FEES PAID

PART 1: IDENTIFICATION

Fields to be completed	**Form Edits**	***Results of incorrect field***
1.1 Client ID	- invalid client ID	FORM REJECTED
	- if client ID is ineffective for the entire production year to which the form relates	FORM REJECTED
1.2 Client name	- no edit checks	
1.3 Production year	- if less than the 1994 production year	FORM REJECTED
	- if greater than the current production year	FORM REJECTED
	- if AC5-V1 is used for production year greater than or equal to 1997	FORM REJECTED
	- if AC5-V2 is used for production year less than 1997	FORM REJECTED
1.4 Date prepared	- invalid date	FORM REJECTED
	- if date prepared is less than the date prepared of the current version on file	FORM REJECTED
	- if greater than the current date	FORM REJECTED
1.5 Contact person	- no edit checks	accept as entered
1.6 Telephone	- no edit checks	accept as entered

AC5 FORM: ALLOWABLE COSTS CUSTOM PROCESSING FEES PAID

ART 2: NON OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

Fields to be completed		**Form Edits**	***Results of incorrect field***
2.1	Custom processing fee paid	- if less than or equal to zero	LINE REJECTED
		- if blank and corresponding 2.2 exists	LINE REJECTED
		Note: must be rounded to nearest dollar	
2.2	Province	- if not AB, BC, or SK	LINE REJECTED
	Facility type	- if not GP or GS	LINE REJECTED
	EUB facility code	- if facility code is ineffective for the entire production year to which the form relates	LINE REJECTED
		- if blank and corresponding 2.1 exists	LINE REJECTED
		- if facility code is listed in both 2.2 and 3.1	LINE REJECTED
		- invalid facility ID	LINE REJECTED
		- if royalty client does not have volumes for this facility code for the production year to which the form relates	LINE REJECTED
2.3	Authorized signature	- if PART 2 data exists and no signature is present	ALL LINES IN PART 2 REJECTED

AC5 FORM: ALLOWABLE COSTS CUSTOM PROCESSING FEES PAID

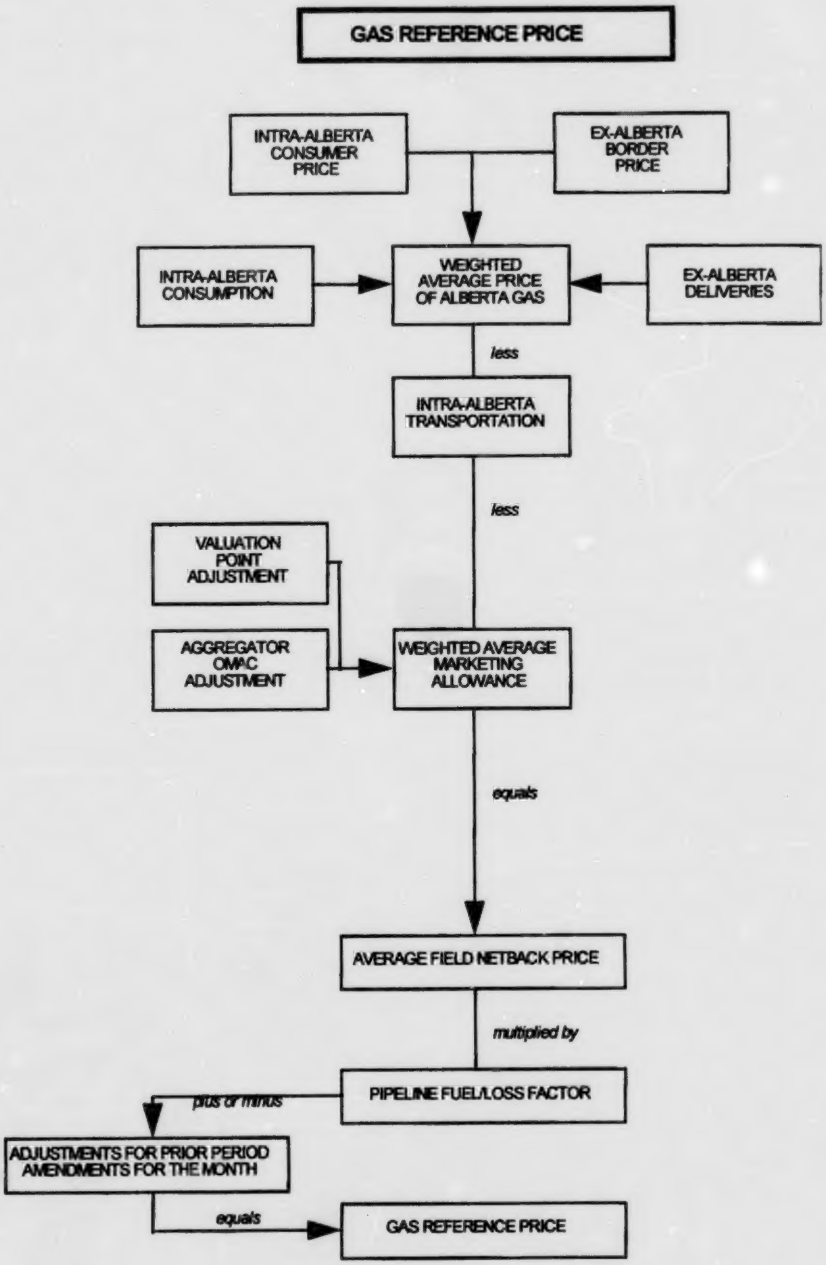
PART 3: OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

Fields to be completed		***Form Edits***	***Results of Incorrect field***
3.1	Province	- if not AB, BC, or SK	LINE REJECTED
	Facility type	- if not GP or GS	LINE REJECTED
	EUB facility code	- if facility code is ineffective for the entire production year to which the form relates	LINE REJECTED
		- if blank and corresponding 3.3, 3.4 and 3.5 exist	LINE REJECTED
		- invalid facility ID	LINE REJECTED
		- if facility code is incomplete	LINE REJECTED
		- if royalty client does not have volumes for this facility code for the production year to which this form relates	LINE REJECTED
		- if facility code is listed in both 2.2a and 3.1	LINE REJECTED
3.2	Custom processing fee paid	- if less than or equal to zero Note: must be rounded to nearest dollar	LINE REJECTED
	V1 only ct code	- if invalid product code - if blank and corresponding 3.1, 3.2, 3.4 and 3.5 exist	REJECTED
	AC5-V2 only Energy-adjusted gas equivalent volume	- if less than or equal to zero (one decimal place only) - if blank and corresponding 3.1, 3.2, 3.4 and 3.5 exist **NOTE: THIS IS A VOLUME FIELD ONLY, NO PRODUCT CODE REQUIRED ON AC5 – V2**	REJECTED

AC5 FORM: ALLOWABLE COSTS CUSTOM PROCESSING FEES PAID

PART 3: OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

Fields to be completed		***Form Edits***	***Results of incorrect field***
3.4	**AC5-V1 only Volume**	- if less than or equal to zero (one decimal place only) - if blank and corresponding 3.1, 3.2, 3.3 and 3.5 exist	LINE REJECTED
	AC5-V2 only Excess capacity	- if this field is not blank and contains anything more than a check mark **NOTE: CHECK ONLY IF EXCESS CAPACITY APPLIES**	LINE REJECTED
3.5	Compressing code Gathering code Processing code	- if these fields are not blank and contains anything more than a check mark **Note:** If compressing, gathering, and processing codes are all blank the calculation will default to using the total unit operating cost at the EUB facility as operating cost recovery	LINE REJECTED
3.6	Authorized signature	- if PART 3 data exists and no signature is present	ALL LINES IN PART 3 REJECTED
PART 2 / PART 3		- if this is an original submission and only PART 1 exists	FORM REJECTED


GAS REFERENCE PRICE
INTRA-ALBERTA CONSUMER PRICE
EX-ALBERTA BORDER PRICE
INTRA-ALBERTA CONSUMPTION
WEIGHTED AVERAGE PRICE OF ALBERTA GAS
EX-ALBERTA DELIVERIES
less
INTRA-ALBERTA TRANSPORTATION
less
VALUATION POINT ADJUSTMENT
AGGREGATOR OMAC ADJUSTMENT
WEIGHTED AVERAGE MARKETING ALLOWANCE
equals
AVERAGE FIELD NETBACK PRICE
multiplied by
PIPELINE FUEL/LOSS FACTOR
plus or minus
ADJUSTMENTS FOR PRIOR PERIOD AMENDMENTS FOR THE MONTH
equals
GAS REFERENCE PRICE

1. For ex-Alberta transactions, actual transportation costs net of any revenue resulting from brokered capacity (including demand and reservation charges) are deducted from sales value to determine the value reported at the export point. For ex-Alberta Gas LDCs (1996 - forward), actual intra-Alberta transportation costs net of any revenue resulting from brokered capacity are added to intra-Alberta purchase value to determine the value reported at the export point.

2. The allowances for transporting gas in Alberta are:

   - a deduction for intra-Alberta transportation fees, *and*
   - a factor to recognize the costs of pipeline fuel consumption and gas loss.

   The **Intra-Alberta Transportation** deduction is Nova's cost-of-service divided by net Nova billable receipts. The **Pipeline Fuel/Loss Factor** is Nova's ratio of net billable receipts (after fuel and losses) to gross billable receipts. The Department calculates both allowances for each production month.

   The reference price calculation does not include deductions for take-or-pay costs. The Department and industry will negotiate the treatment of such costs if and when it becomes necessary to do so.

3. The **Marketing Allowance** is a weighted average of marketing costs incurred for producers' sales to two purchaser groups:

   - marketers, *and*
   - aggregators.

   The adjustments attributable to each of these groups have been classified as follows:

   - Aggregator OMAC Adjustment - rate is determined by the Department each month as a proxy for the overhead, marketing and administration charges of recognized aggregators. The rate will be the weighted average OMAC type deduction of the designated large aggregators multiplied by the total percentage that the recognized aggregators volumes were of the total gas dispositions (for 1994 only), and the total gas removals from Alberta (for 1995 and onwards) in the previous year, *and*
   - Valuation Point Adjustment (VPA) - is calculated as the average difference between purchases and sales prices obtained for companies identified as marketers by the Department. This is multiplied by the percentage that marketers were of the total gas dispositions (for 1994 only) and the total gas removals from Alberta (for 1995 and onwards), in the previous year. (For 1994 only, volumes purchased by marketers are net of the purchased portion of net injection calculated using the latest year for which that data is available.) For 1994, the average difference is deemed to be 10¢/GJ. Future average differences will be calculated based on Department surveys of marketers.

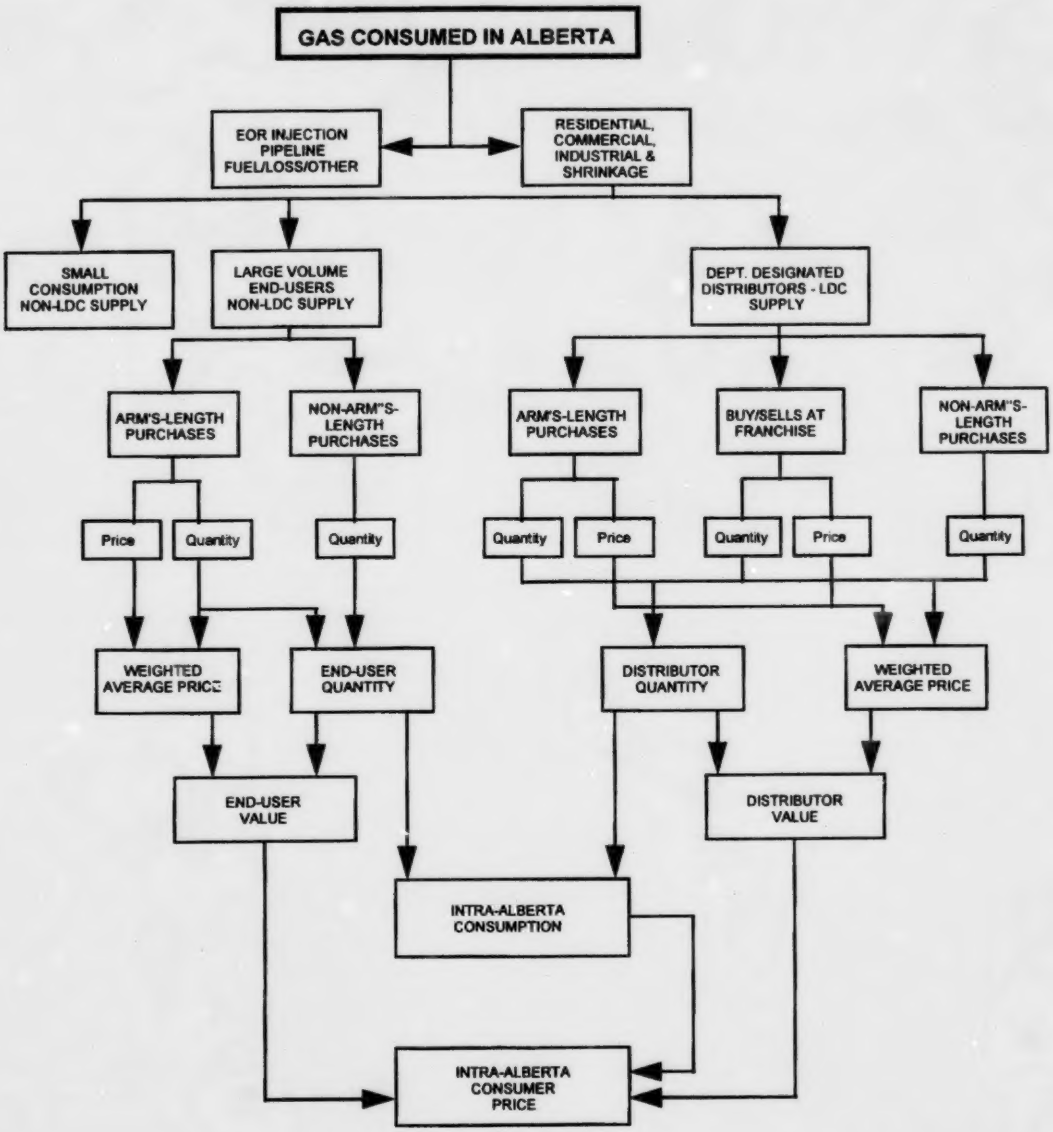
4. **Adjustments for Prior Period Amendments for the Month** is calculated as follows:

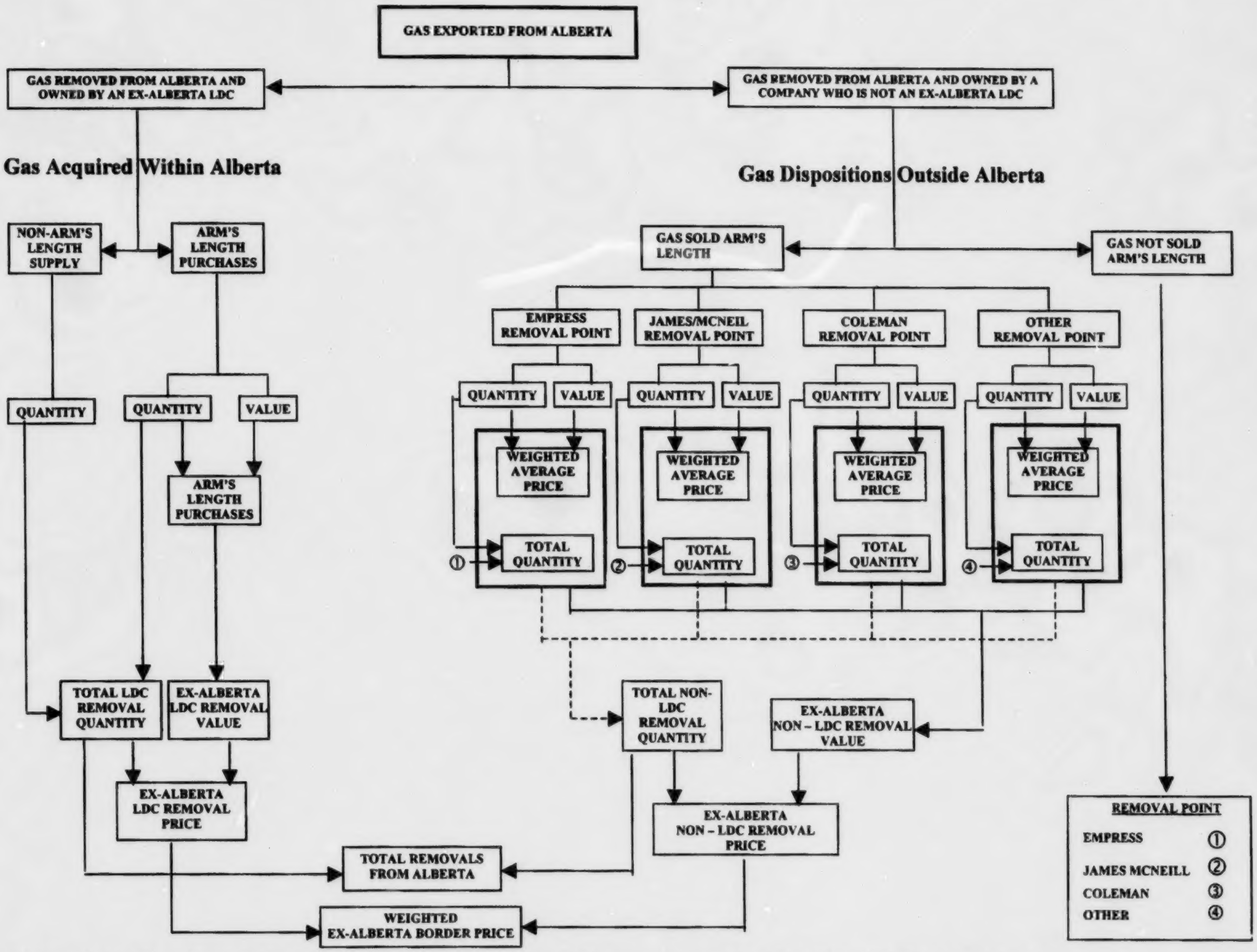
   i. For every delivery month amended in the current month's Gas Reference Price business period:
   Recalculate the Gas Reference Price before adjustments for prior period amendments and rounding. Compare the recalculated Gas Reference Price to the previous business period's Gas Reference Price. The unit difference ($/GJ), is multiplied by the total Gas Reference Price Quantity (GJ), as at the current business period, to generate an amendment value ($).

   ii. The sum of all months' amendment values plus the opening rollover balance divided by the current month's Gas Reference Price quantity equals the current month's Prior Period Amendment Adjustment.

   iii. The maximum Prior Period Amendment Adjustment included in any current Reference Price month is an amount equal to plus or minus 2% of the Gas Reference Price before the Prior Period amendment Adjustment. Any amount that is over the 2% limit is carried forward to the next succeeding Reference Price month.

The following chart shows how the Department calculates the **intra-Alberta consumers' price** from monthly arm's-length purchases by designated Local Distribution Companies (LDCs) and Large Volume End-users.


GAS CONSUMED IN ALBERTA
EOR INJECTION PIPELINE FUEL/LOSS/OTHER
RESIDENTIAL, COMMERCIAL, INDUSTRIAL & SHRINKAGE
SMALL CONSUMPTION NON-LDC SUPPLY
LARGE VOLUME END-USERS NON-LDC SUPPLY
DEPT. DESIGNATED DISTRIBUTORS - LDC SUPPLY
ARM'S-LENGTH PURCHASES
NON-ARM"S-LENGTH PURCHASES
ARM'S-LENGTH PURCHASES
BUY/SELLS AT FRANCHISE
NON-ARM"S-LENGTH PURCHASES
Price
Quantity
Quantity
Quantity
Price
Quantity
Price
Quantity
WEIGHTED AVERAGE PRICE
END-USER QUANTITY
DISTRIBUTOR QUANTITY
WEIGHTED AVERAGE PRICE
END-USER VALUE
DISTRIBUTOR VALUE
INTRA-ALBERTA CONSUMPTION
INTRA-ALBERTA CONSUMER PRICE


GAS EXPORTED FROM ALBERTA
GAS REMOVED FROM ALBERTA AND OWNED BY AN EX-ALBERTA LDC
GAS REMOVED FROM ALBERTA AND OWNED BY A COMPANY WHO IS NOT AN EX-ALBERTA LDC
Gas Acquired Within Alberta
Gas Dispositions Outside Alberta
NON-ARM'S LENGTH SUPPLY
ARM'S LENGTH PURCHASES
GAS SOLD ARM'S LENGTH
GAS NOT SOLD ARM'S LENGTH
EMPRESS REMOVAL POINT
JAMES/MCNEIL REMOVAL POINT
COLEMAN REMOVAL POINT
OTHER REMOVAL POINT
QUANTITY
VALUE
WEIGHTED AVERAGE PRICE
TOTAL QUANTITY
ARM'S LENGTH PURCHASES
①
②
③
④
TOTAL LDC REMOVAL QUANTITY
EX-ALBERTA LDC REMOVAL VALUE
TOTAL NON-LDC REMOVAL QUANTITY
EX-ALBERTA NON – LDC REMOVAL VALUE
EX-ALBERTA LDC REMOVAL PRICE
EX-ALBERTA NON – LDC REMOVAL PRICE
TOTAL REMOVALS FROM ALBERTA
WEIGHTED EX-ALBERTA BORDER PRICE
REMOVAL POINT
EMPRESS ①
JAMES MCNEILL ②
COLEMAN ③
OTHER ④

This chart shows how the Ministry calculates the **ex-Alberta border price** from arm's-length transactions reported by companies removing gas from Alberta. The distinct calculation for ex-Alberta Gas LDCs commenced with January 1996. Prior to January 1996, removals by ex-Alberta LDCs were considered non-arm's length transactions under each removal point.

Overview

The Propane Floor Price and Butane Floor Price (*refer to Section 15.1.3*) are calculated by the Department to protect the Crown against inappropriately depressed prices in the Edmonton market. Both the Propane Floor Price and the Butane Floor Price are calculated based on the Edmonton netback value of posted prices at Conway, Kansas.

1. Calculate the Propane Floor Price

- Determine the Edmonton netback propane price in the units in which it is posted (U.S. cents per U.S. gallon):

Conway posted price for Specification Propane
...minus...
transportation from Edmonton to Iowa City
...minus...
transportation from Iowa City to Conway (including storage cost)

- Convert the Edmonton netback propane price to U.S. dollars per barrel:

U.S. cents per U.S. gallon
...multiplied by...
42 (U.S. gallons per barrel)
...divided by...
100 (cents per dollar)

- Convert the Edmonton netback propane price to Canadian dollars per cubic metre:

U.S. dollars per barrel
...divided by...
0.15891 (m^3 per barrel)
...multiplied by...
Exchange Rate (Canadian dollars per U.S. dollar)

- Convert the Edmonton netback propane price to the Propane Floor Price:

Canadian dollars per m^3 (at Edmonton)
...multiplied by...
0.90 (conversion factor)

2. Calculate the Butane Floor Price

- Determine the Edmonton netback butane price in the units in which it is posted (U.S. cents per U.S. gallon):

[Conway Posted Price for Normal Butane ...*times*... 0.65]
...plus...
[Conway Posted Price for Iso Butane ...*times*... 0.35]
...minus...
transportation from Edmonton to Iowa City
...minus...
transportation from Iowa City to Conway (including storage cost)

- Convert the Edmonton netback butane price to U.S. dollars per barrel:

U.S. cents per U.S. gallon
...multiplied by...
42 (U.S. gallons per barrel)
...divided by...
100 (cents per dollar)

- Convert the Edmonton netback butane price to Canadian dollars per cubic metre:

U.S. dollars per barrel
...divided by...
0.15891 (m^3 per barrel)
...multiplied by...
exchange rate (Canadian dollars per U.S. dollar)

- Convert the Edmonton netback butane price to the Butane Floor Price:

Canadian dollars per m^3 (at Edmonton)
...multiplied by...
0.90 (conversion factor)

3. Canada/United States Exchange Rate

The exchange rate (Canadian dollars per U.S. dollar) employed by the Department in calculating the Propane Floor Price and the Butane Floor Price is the monthly average Bank of Canada rate. The Department will obtain the exchange rate each month from the Alberta Treasury Branch.

4. Definition and Source of Posted Prices and Rates

- Conway posted price for propane is the average of daily *any barrel* posted prices for specification condition propane delivered at Conway, Kansas. *Any barrel* refers to the price for delivery at any time during the month of posting.

  SOURCE: OIL PRICE INFORMATION SERVICE (OPIS)

- Conway posted price for butane is based on a field butane stream comprising 65% normal butane and 35% iso butane. Prices for both normal and iso butane are the average of daily prices for delivery at Conway, Kansas.

  SOURCE: OIL PRICE INFORMATION SERVICE (OPIS)

- Transportation cost from Edmonton to Iowa City is the published monthly Cochin pipeline tariff, including incentive rates.

  SOURCE: TARIFF BULLETINS SANCTIONED BY THE FERC (U.S.) AND NEB (CANADA)

- Transportation cost from Iowa City to Conway is the published monthly Mid-America Pipeline Company tariff, including incentive rates, for transportation between the two cities.

  SOURCE: TARIFF BULLETINS SANCTIONED BY THE FERC (U.S.)

- Storage cost at Conway is an allowance for storage costs incurred in transporting and processing propane and butane.

  SOURCE: INCLUDED IN MID-AMERICA PIPELINE COMPANY TARIFF

Overview

The Transportation Allowances applied as a deduction from NGL reference prices *(refer to Section 15.3.1)* are defined in the context of the geographical regions described below and depicted on the map provided.

1. NGL Transportation Region 1

NGL Transportation Region 1 *(for definition of Transportation Region, please see Appendix N - Glossary)* is defined as the area:

- bounded on the NORTH by:
  - the north border of the 70th township
- bounded on the EAST by:
  - the 4th meridian
- bounded on the SOUTH by:
  - the south border of the 35th township
- bounded on the WEST by:
  - the west border of the 13th range west of the 5th meridian

2. NGL Transportation Region 2

NGL Transportation Region 2 is defined as the area:

- bounded on the NORTH by:
  - the span of the north border of the 35th township between the 4th meridian and the west border of the 13th range west of the 5th meridian, *and*
  - the span of the north border of the 56th township between the east border of the 14th range west of the 5th meridian and the Alberta-British Columbia border
- bounded on the EAST by:
  - the 4th meridian, from the 49th parallel to the north border of the 34th township, *and*
  - the east border of the 14th range west of the 5th meridian, from the south border of the 35th township to the north border of the 56th township
- bounded on the SOUTH by:
  - the 49th parallel; and
- bounded on the WEST by:
  - the Alberta-British Columbia border

3. NGL Transportation Region 3

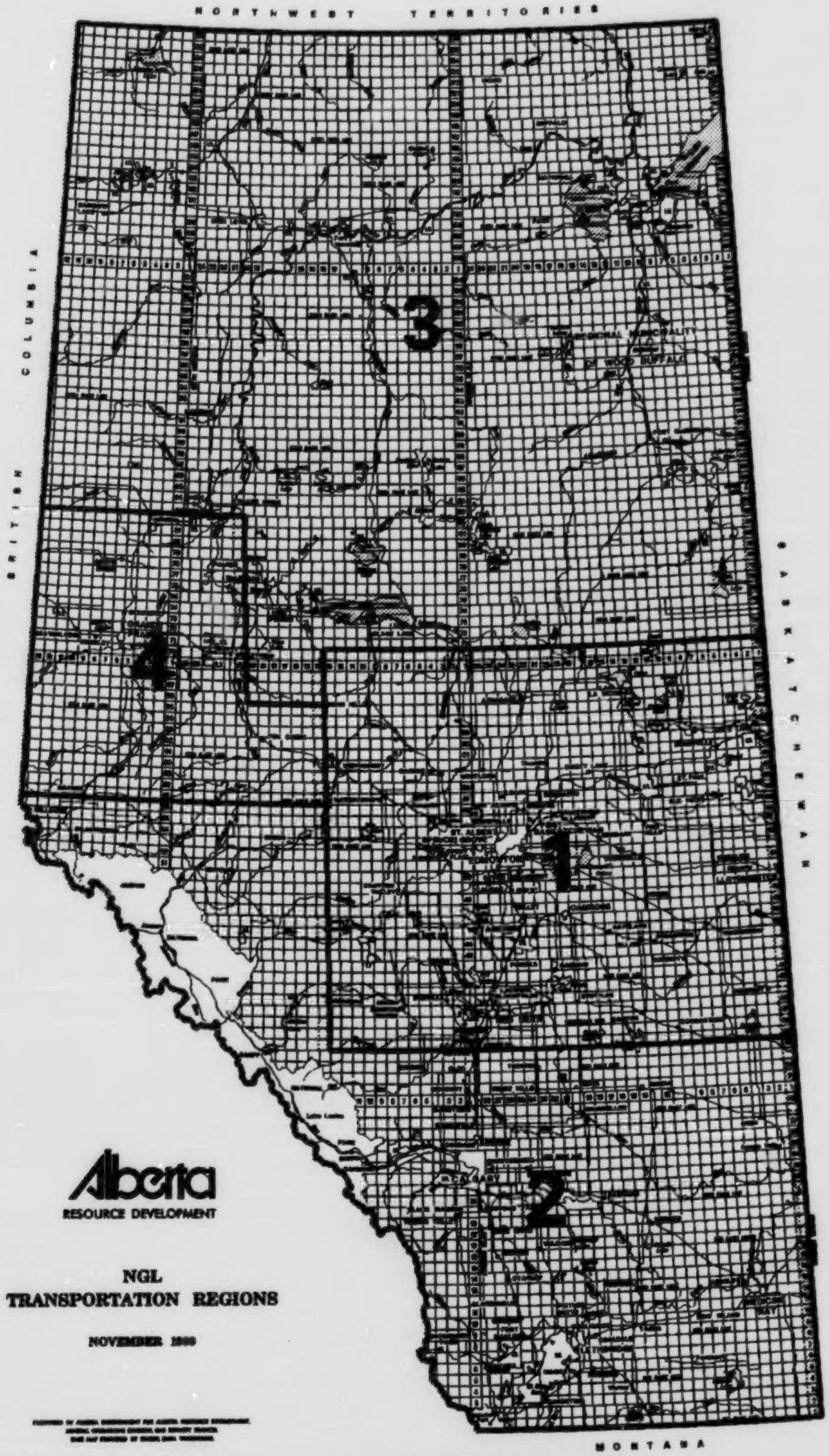
NGL Transportation Region 3 is defined as the area:

- bounded on the NORTH by:
    - Alberta-N.W.T. border
- bounded on the EAST by:
    - the 4th meridian, from the south border of the 71st township north, *and*
    - the west border or the 13th range west of the 5th meridian, from the north border of the 65th township to the south border of the 71st township
- bounded on the SOUTH by:
    - the south border of the 71st township, from the 4th meridian to the west border of the13th range west of the 5th meridian, *and*
    - the south border of the 66th township, from the east border of the 14th range west of the 5th meridian to the west border of the 20th range west of the 5th meridian, *and*
    - the south border of the 83rd township, from the east border of the 21st range west of the 5th meridian to the Alberta-British Columbia border; and
- bounded on the WEST by:
    - the west border of the 20th range west of the 5th meridian, from the south border of the 66th township to the north border of the 82nd township, *and*
    - the Alberta-British Columbia border from the south border of the 83rd township north to the Alberta-N.W.T. border

4. NGL Transportation Region 4

NGL Transportation Region 4 is defined as the area:

- bounded on the NORTH by:
    - the north border of the 65th township, from the east border of the 14th range west of the 5th meridian to the west border of the 20th range west of the 5th meridian, *and*
    - the north border of the 82nd township, from east border of the 21st range west of the 5th meridian to the Alberta-British Columbia border
- bounded on the EAST by:
    - the east border of the 14th range west of the 5th meridian, from the south border of the 57th township to the north border of the 65th township, *and*
    - the east border of the 21st range west of the 5th meridian, from the south border of the 66th township line to the north border of the 82nd township
- bounded on the SOUTH by:
    - the south border of the 57th township
- bounded on the WEST by:
    - the Alberta-British Columbia border


NORTHWEST TERRITORIES
BRITISH COLUMBIA
SASKATCHEWAN
MONTANA
3
4
1
2
ST. ALBERT
Alberta
RESOURCE DEVELOPMENT
NGL
TRANSPORTATION REGIONS
NOVEMBER

Overview

The Minister may approve additions/deletions to the list of allowable costs or require additions to the list of non-allowable costs. Where such an addition/deletion occurs, the Department:

- will announce the addition directly to the applicant and in an *Information Letter*; and
- will include that addition in the next update of the *Principles and Procedures* Manual.

1. Allowable Capital Costs

The following are *allowable capital costs* identified by the Minister, as referenced in *Section 16.4*:

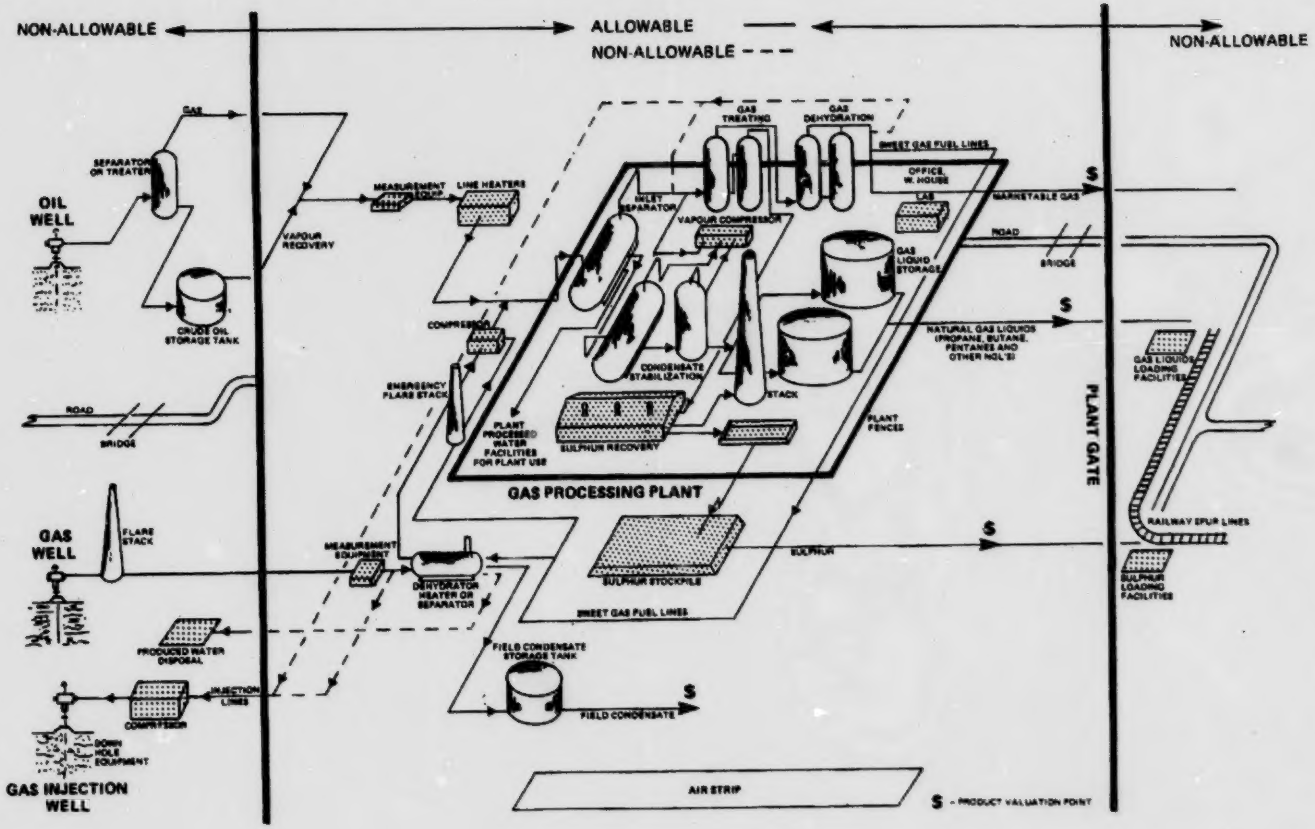
- air strips
- automatic equipment for gathering, compressing and processing facilities
- communication controls
- compressor facilities for acceptance to the plant inlet or purchaser's specifications
- construction overhead as specified in joint venture agreements, or in the absence of a joint venture agreement, overhead on construction will not exceed 1% of direct capital costs
- corrosion protection
- cost of easements or rights-of-way
- effluent basins and facilities for process water
- emergency flare stacks and relief facilities
- fire fighting and safety equipment
- fuel lines
- gas recovery related costs occurring after the point of final separation of solution gas from oil
- installed costs of gathering lines to the plant or field compressor from the gas wells, or from the point of final separation for solution gas from oil
- actual or imputed interest or other financing costs, not exceeding the prime rate of interest charged by the Alberta Treasury Branch plus 1%, will be allowed as part of the cost of new facility and capital additions to an existing facility up to the production start-up date
- line heaters at well heads and on gathering systems
- meter runs and measurement equipment
- on-site training facilities
- pollution monitoring and seepage detection equipment
- process license fees
- processing facilities
- processing studies that relate directly to the process used
- roads, bridges, walkways and fences for compressing and processing facilities only
- separators, dehydrators, scrubbers, etc., for non-associated gas
- storage tanks for field separated liquids other than oil and water
- sulphur-forming facilities (prilling, slates and remelts) effective as of January 1990
- vehicles and mobile equipment
- warehouses, laboratories and plant offices
- water treatment facilities if water is used for processing

2. Non-Allowable Capital Costs

The following are the *non-allowable capital costs* approved by the Minister, as referenced in *Section 16.4*:

- crude oil equipment
- storage, separators, dehydrators, scrubbers, boots, and any other facilities or equipment relating to oil
- ext-plant-gate equipment
- loading facilities, railway spur lines, storage, or other facilities beyond the plant gate
- housing
- other than those costs directly attributable to the gathering, compressing and processing functions as they relate to natural gas
- injection equipment
- lines, compressors, wells and other significant facilities or equipment relating to the injection function
- off-site depots for vehicles and equipment servicing more than one facility.
- off-site training facilities
- production equipment
- down hole, wellhead, protection, controlling, servicing, testing, salt water, and other production facilities or equipment relating to the production function
- SECAP equipment
- equipment approved under the Sulphur Emission Control Assistance Program
- shared production/gathering equipment
- roads, bridges, walkways and fences for wellhead and gathering facilities.

ALLOWABLE AND NON-ALLOWABLE CAPITAL COSTS


NON-ALLOWABLE
ALLOWABLE ——
NON-ALLOWABLE - - -
NON-ALLOWABLE
OIL WELL
SEPARATOR OR TREATER
GAS
CRUDE OIL STORAGE TANK
VAPOUR RECOVERY
MEASUREMENT EQUIPMENT
LINE HEATERS
ROAD
BRIDGE
COMPRESSOR
EMERGENCY FLARE STACK
GAS WELL
FLARE STACK
MEASUREMENT EQUIPMENT
DEHYDRATOR HEATER OR SEPARATOR
PRODUCED WATER DISPOSAL
INJECTION LINES
COMPRESSOR
DOWN HOLE EQUIPMENT
GAS INJECTION WELL
GAS TREATING
GAS DEHYDRATION
SWEET GAS FUEL LINES
INLET SEPARATOR
VAPOUR COMPRESSOR
OFFICE, W. HOUSE
LAB
GAS LIQUID STORAGE
CONDENSATE STABILIZATION
STACK
SULPHUR RECOVERY
PLANT PROCESSED WATER FACILITIES FOR PLANT USE
PLANT FENCES
GAS PROCESSING PLANT
SULPHUR STOCKPILE
SULPHUR
SWEET GAS FUEL LINES
FIELD CONDENSATE STORAGE TANK
FIELD CONDENSATE
AIR STRIP
$
MARKETABLE GAS
ROAD
BRIDGE
NATURAL GAS LIQUIDS (PROPANE, BUTANE, PENTANES AND OTHER NGL'S)
PLANT GATE
GAS LIQUIDS LOADING FACILITIES
RAILWAY SPUR LINES
SULPHUR LOADING FACILITIES
$ - PRODUCT VALUATION POINT

Overview

The Minister may approve additions/deletions to the list of allowable costs or require additions/deletions to the list of non-allowable costs. Where such an addition/deletion occurs, the Department:

- will announce the addition directly to the applicant and in an *Information Letter*; *and*
- will include that addition in the next update of the *Principles and Procedures* manual.

1. Allowable Operating Costs

The following are *allowable operating costs* identified by the Minister, as referenced in *Section 16.11*:

- automotive
- chemicals
- contract services
- gain or loss on disposal of capital assets which are replaced
- insurance other than loss of revenue
- labour
- maintenance
- materials
- overhead allowance
- process licence royalties or fees
- property taxes
- purchase fuel gas
- repairs
- road maintenance for compressing and processing facilities
- service costs
- surface rentals
- transportation
- utilities

2. Non-Allowable Operating Costs

The following are *non-allowable operating costs* approved by the Minister, as referenced in *Section 16.11*:

- EUB tax assessment
- compensatory payment to other well owners
- compensatory royalty payments
- custom fees
- loss of revenue insurance
- mineral taxes
- operating costs associated with non-allowable capital costs
- operating costs related to production, injection or oil functions
- petroleum and natural gas royalties
- production lease rentals
- road maintenance for gathering facilities.

The following is the list of the EUB Designated Facilities and their corresponding Plant Types:

DESIGNATED EUB FACILITY	PLANT TYPE	DESIGNATED EUB FACILITY	PLANT TYPE
1002	5	1108	5
1097	2	1058	4
1004	5	1107	5
1020	5	1131	5
1022	2	1132	3
1034	5	1133	5
1084	5	1141	5
1037	5	1144	5
1042	2	1147	5
1045	5	1169	2
1074	4	1173	2
1047	5	1292	2
1050	5	1350	2
1054	5	1351	2
1056	5	1360	5
1060	5	1458	5
1069	4	1520	5
1079	5	1522	2
1105	5	1662	5

Designated Facilities

The following are the Designated Facilities at January 1, 1999 (*please refer to Section 16.3*) together with the 1999 Unit Operating Cost Rates (UOCR) and the delayered UOCR for each.

			DELAYERED RATES		
EUB FACILITY NUMBER	FACILITY NAME	UOCR ($\$/10^3m^3$)	COMPRESSING ($\$/10^3m^3$)	GATHERING ($\$/10^3m^3$)	PROCESSING ($\$/10^3m^3$)
1002	WESTERN NEVIS	25.58	6.62	3.95	15.01
1004	GULF HOMEGLEN-RIMBEY	8.79	2.51	3.07	3.21
1020	ANDERSON CARSTAIRS	-2.40	-0.75	-0.40	-1.25
1022	CRESTAR CESSFORD	7.35	0.00	3.00	4.35
1034	AMOCO WINDFALL	23.53	4.93	8.61	9.99
1037	SHELL JUMPING POUND	9.97	1.82	1.57	6.58
1042	RIO ALTO KARR	8.73	0.36	2.13	6.24
1045	ESSO BONNIE GLEN	9.45	0.00	0.27	9.18
1047	PENN WEST MINNEHIK-BUCK LAKE	17.33	3.94	3.25	10.14
1050	WASCANA CROSSFIELD	25.77	1.00	3.45	21.32
1054	PETRO-CAN WILDCAT HILLS	14.79	1.25	2.54	11.00
1056	SHELL WATERTON	26.45	4.25	3.57	18.63
1058	PETRO-CAN KAYBOB	11.44	4.64	3.08	3.72
1060	NOVAGAS HARMATTAN ELKTON	11.59	2.42	1.24	7.93
1069	ESSO JUDY CREEK	19.27	4.87	1.05	13.35
1074	ESSO BONNIE GLEN	10.56	0.00	0.00	10.56
1079	AMOCO CROSSFIELD EAST	35.14	0.61	12.02	22.51
1084	TALISMAN EDSON	10.38	0.89	3.43	6.06
1097	GULF GHOST PINE	6.15	0.87	3.41	1.87
1105	HUSKY RAINBOW	6.02	0.00	0.75	5.27
1107	AMOCO KAYBOB S #1	18.03	1.15	5.88	11.00
1108	GULF BRAZEAU RIVER	14.57	4.73	3.06	6.78
1131	SHELL BURNT TIMBER	4.98	0.47	1.70	2.81
1132	AMOCO MARTEN HILLS	6.59	2.65	2.42	1.52
1133	GULF STRACHAN (B)	11.08	0.90	3.01	7.17
1141	HUSKY STRACHAN	8.54	1.20	2.74	4.60
1144	CHEVRON KAYBOB SOUTH	13.31	1.86	4.27	7.18
1147	AEC SINCLAIR	-2.11	-0.83	-0.74	-0.54
1169	ANDERSON DUNVEGAN	6.11	0.69	3.09	2.33
1173	AMOCO RICINUS (B)	6.41	1.53	1.58	3.30
1292	AMOCO WAPITI	7.49	3.68	2.60	1.21
1350	CDN HUNTER ELMWORTH	6.41	4.31	1.44	0.66
1351	ULSTER ELMWORTH	6.49	3.74	1.44	1.31
1360	PETRO-CAN BANSHEE	7.53	0.20	1.98	5.35
1458	DM WOLCOTT BRAZEAU RIVER	9.27	0.90	1.71	6.66
1520	CRESTAR WEMBLEY	9.55	2.13	3.03	4.39
1522	SHELL HAMBURG	5.61	0.41	0.62	4.58
1662	SHELL CAROLINE	8.98	1.51	0.50	6.97

Plant Types

The following are the five Plant Types at January 1, 1999 (*refer to Section 16.3*), together with the 1999 Unit Operating Cost Rates (UOCR) and the delayered UOCR for each.

			DELAYERED RATES		
PLANT TYPE	TYPE DESCRIPTION	FACILITY $\$/10^3m^3$UOCR	COMPRESSING $\$/10^3m^3$UOCR	GATHERING $\$/10^3m^3$UOCR	PROCESSING $\$/10^3m^3$UOCR
1	DRY GAS WITH DEHYDRATION/ COMPRESSION OR GATHERING SYSTEM WITH SALES	6.39	3.56	2.50	0.33
2	WET GAS WITH DEHYDRATION, COMPRESSION AND C3+ EXTRACTION	7.22	1.15	1.86	4.21
3	DRY GAS WITH SULPHUR REMOVAL	5.24	1.18	0.99	3.07
4	WET GAS WITH SULPHUR REMOVAL	10.71	1.79	1.46	7.46
5	DRY AND WET GAS WITH SULPHUR RECOVERY	13.27	1.31	2.02	9.94

PLANT TYPE 1 (DRY GAS WITH DEHYDRATION/COMPRESSION OR GATHERING SYSTEM WITH SALES)

- An EUB-approved sweet gas plant where dry sweet gas is dehydrated and compressed. Plants using non-regenerative sweetening will also be included in this plant type if the only other processing is related to dehydration and compression. The product produced is pipeline quality gas.

PLANT TYPE 2 (WET GAS WITH DEHYDRATION, COMPRESSION AND C3 + EXTRACTION)

- An EUB-approved sweet gas plant with dehydration, natural gas liquids recovery and compression. Plants using non-regenerative sweetening will also be included in this plant type if the only other processing is related to dehydration, natural gas liquids recovery and compression. The products produced are pipeline quality gas and natural gas liquids.

PLANT TYPE 3 (WET GAS WITH DEHYDRATION, COMPRESSION, AND C3+ EXTRACTION)

- An EUB-approved sour gas plant with acid gas removal and acid gas flaring, dehydration and compression. The product produced is pipeline quality gas.

PLANT TYPE 4 (WET GAS WITH SULPHUR REMOVAL)

- An EUB-approved sour gas plant with acid gas removal and acid gas flaring, dehydration, natural gas liquids recovery and compression. The products produced are pipeline quality gas and natural gas liquids.

PLANT TYPE 5 (DRY AND SULPHUR RECOVERY)

- An EUB-approved sour gas plant with acid gas removal and a sulphur recovery process, or non-flaring acid gas processing, dehydration and compression. The products produced are pipeline quality gas and sulphur.
- Also included in this category an EUB-approved sour gas plant with acid gas removal and sulphur recovery or a non-flaring acid gas disposal process, dehydration, natural gas liquids recovery and compression. The products are pipeline quality gas, natural gas and liquids and sulphur.

1998 Designated and Plant Type Unit Operating Cost Rates

			DELAYERED RATES		
EUB FACILITY NUMBER	FACILITY NAME	FACILITY \$/10^3m^3 UOCR	COMPRESSING \$/10^3m^3 UOCR	GATHERING \$/10^3m^3 UOCR	PROCESSING \$/10^3m^3 UOCR
1002	NEVIS	19.48	5.80	2.99	10.69
1004	HOMEGLEN-RIMBEY	5.30	2.00	1.37	1.93
1020	CARSTAIRS	18.64	4.67	2.91	11.06
1022	CESSFORD	8.79	0.00	2.83	5.96
1034	WINDFALL	13.47	2.99	4.94	5.54
1037	JUMPING POUND	14.46	3.19	1.65	9.62
1042	KARR	9.40	0.54	1.68	7.18
1045	BONNIE GLEN	13.77	0.00	0.41	13.36
1047	MINNEHIK-BUCK LAKE	1.69	0.38	0.36	0.95
1050	CROSSFIELD	-0.82	-0.03	-0.11	-0.68
1054	WILDCAT HILLS	11.54	1.26	1.82	8.46
1056	WATERTON	12.17	2.57	1.41	8.19
1058	KAYBOB	13.51	5.81	4.24	3.46
1060	HARMATTAN ELKTON	10.68	2.35	1.03	7.30
1069	JUDY CREEK	25.95	6.45	1.34	18.16
1074	BONNIE GLEN	5.61	0.00	0.00	5.61
1079	CROSSFIELD EAST	28.63	1.04	9.31	18.28
1084	EDSON	1.81	0.24	0.58	0.99
1097	GHOST PINE	4.09	0.65	2.22	1.22
1105	RAINBOW	9.15	0.00	1.04	8.11
1107	KAYBOB S #1	17.55	0.77	5.66	11.12
1108	BRAZEAU RIVER	13.37	3.68	3.64	6.05
1131	BURNT TIMBER	14.93	1.19	3.76	9.98
1132	MARTEN HILLS	7.47	3.36	2.40	1.71
1133	STRACHAN (B)	4.84	0.74	1.14	2.96
1141	STRACHAN	6.99	0.57	2.05	4.37
1144	KAYBOB SOUTH	22.42	3.05	5.64	13.73
1147	SINCLAIR	16.66	13.46	1.88	1.32
1169	DUNVEGAN	9.35	1.07	4.71	3.57
1173	RICINUS (B)	5.11	1.21	1.50	2.40
1292	WAPITI	6.37	3.13	2.20	1.04
1350	ELMWORTH	7.35	4.90	1.90	0.55
1351	ELMWORTH	6.28	3.07	1.79	1.42
1360	BANSHEE	4.86	0.21	1.43	3.22
1458	BRAZEAU RIVER	6.63	0.67	1.08	4.88
1520	WEMBLEY	9.79	2.29	2.18	5.32
1522	HAMBURG	5.38	0.02	0.24	5.12
1662	CAROLINE	13.25	2.63	0.63	9.99
Plant Types					
1		6.09	3.40	2.38	0.31
2		6.89	1.10	1.78	4.01
3		5.30	1.20	1.00	3.10
4		10.64	1.77	1.45	7.42
5		9.23	0.91	1.41	6.91

1997 Designated and Plant Type Unit Operating Cost Rates

UB FACILITY ID	NAME	UOCR	COMPRESSING	GATHERING	PROCESSING
AB-GP-1002	Nevis	10.95	3.17	2.23	5.55
AB-GP-1004	Homeglen-Rimbey	8.37	2.71	2.21	3.45
AB-GP-1020	Carstairs	17.41	3.98	2.23	11.20
AB-GP-1022	Cessford	14.74	0.00	4.59	10.15
AB-GP-1034	Windfall	13.90	2.48	4.61	6.81
AB-GP-1037	Jumping Pound	13.67	3.36	1.33	8.98
AB-GP-1042	Karr	3.86	0.00	1.50	2.36
AB-GP-1045	Bonnie Glen	4.51	0.00	0.08	4.43
AB-GP-1047	Minnehik Buck Lake	14.60	3.19	2.02	9.39
AB-GP-1050	Crossfield	47.72	2.28	15.74	29.70
AB-GP-1054	Wildcat Hills	7.45	0.71	0.66	6.08
AB-GP-1056	Shell Waterton	14.61	3.20	1.84	9.57
AB-GP-1058	Kaybob	11.58	1.43	3.89	6.26
AB-GP-1060	Harmattan Elkton	9.57	1.66	0.93	6.98
AB-GP-1069	Judy Creek	2.85	0.72	0.15	1.98
AB-GP-1074	Bonnie Glen	4.51	0.00	0.08	4.43
AB-GP-1079	Crossfield East	39.39	1.91	13.15	24.33
AB-GP-1084	Edson	13.90	2.48	4.61	6.81
AB-GP-1097	Ghost Pine	10.95	3.17	2.23	5.55
AB-GP-1105	Rainbow	4.96	0.00	0.48	4.48
AB-GP-1107	Kaybob South	11.58	1.43	3.89	6.26
AB-GP-1108	Brazeau River	1.81	0.59	0.48	0.74
AB-GP-1131	Burnt Timber	17.25	2.25	4.61	10.39
AB-GP-1132	Marten Hills	10.26	4.13	2.91	3.22
AB-GP-1133	Gulf Strachan	4.16	0.47	0.84	2.85
AB-GP-1141	Husky Strachan	10.44	1.03	2.29	7.12
AB-GP-1144	Kaybob South	14.70	2.28	3.71	8.71
AB-GP-1147	Sinclair	2.21	1.51	0.33	0.37
AB-GP-1169	Dunvegan	1.36	0.39	0.68	0.29
AB-GP-1173	Ricinus	3.39	0.74	0.92	1.73
AB-GP-1292	Wapiti	3.84	1.81	1.35	0.68
AB-GP-1350	Cdn Hunter Elmworth	10.17	6.29	3.02	0.86
AB-GP-1351	Esso Elmworth	1.98	0.88	0.66	0.44
AB-GP-1360	Hanlan (Banshee)	6.38	0.27	2.05	4.06
AB-GP-1458	Brazeau River	14.92	1.54	2.16	11.22
AB-GP-1520	Wembley	10.33	2.53	2.43	5.37
AB-GP-1522	Hamburg	6.43	0.36	0.93	5.14
AB-GP-1662	Caroline	2.87	0.61	0.06	2.20
PLANT TYPES					
1		6.60	3.68	2.58	0.34
2		7.29	1.16	1.88	4.25
3		6.47	1.46	1.22	3.79
4		14.10	2.35	1.92	9.83
5		10.95	1.08	1.67	8.20

1996 Designated and Plant Type Unit Operating Cost Rates

UB FACILITY ID	NAME	UOCR	COMPRESSING	GATHERING	PROCESSING
AB-GP-1002	Nevis	11.38	3.11	2.30	5.97
AB-GP-1004	Homeglen-Rimbey	5.70	1.88	1.49	2.33
AB-GP-1020	Carstairs	21.68	4.77	2.53	14.38
AB-GP-1022	Cessford	10.59	0.00	4.10	6.49
AB-GP-1034	Windfall	17.93	3.10	6.04	8.79
AB-GP-1037	Jumping Pound	14.00	3.64	1.44	8.92
AB-GP-1042	Karr	1.71	0.05	0.92	0.74
AB-GP-1045	Bonnie Glen	7.46	0.00	0.16	7.30
AB-GP-1047	Minnehik Buck Lake	5.57	1.55	1.07	2.95
AB-GP-1050	Crossfield	7.82	0.63	1.02	6.17
AB-GP-1054	Wildcat Hills	13.21	1.95	1.27	9.99
AB-GP-1056	Shell Waterton	17.76	2.62	2.00	13.14
AB-GP-1058	Kaybob	14.84	1.71	4.85	8.28
AB-GP-1060	Harmattan Elkton	7.04	1.04	0.66	5.34
AB-GP-1069	Judy Creek	16.63	5.10	0.98	10.55
AB-GP-1074	Bonnie Glen	7.46	0.00	0.16	7.30
AB-GP-1079	Crossfield East	26.64	1.15	7.80	17.69
AB-GP-1084	Edson	17.93	3.10	6.04	8.79
AB-GP-1097	Ghost Pine	11.38	3.11	2.30	5.97
AB-GP-1105	Rainbow	3.40	0.00	0.37	3.03
AB-GP-1107	Kaybob South	14.84	1.71	4.85	8.28
AB-GP-1108	Brazeau River	24.06	8.46	4.42	11.18
AB-GP-1131	Burnt Timber	4.97	0.67	1.51	2.79
AB-GP-1132	Marten Hills	8.28	3.16	3.57	1.55
AB-GP-1133	Gulf Strachan	9.85	1.18	2.04	6.63
AB-GP-1141	Husky Strachan	9.33	1.14	2.02	6.17
AB-GP-1144	Kaybob South	10.91	1.76	2.72	6.43
AB-GP-1147	Sinclair	9.49	5.35	0.83	3.31
AB-GP-1169	Dunvegan	5.42	1.61	2.62	1.19
AB-GP-1173	Ricinus	4.58	1.07	1.10	2.41
AB-GP-1292	Wapiti	2.62	1.35	0.77	0.50
AB-GP-1350	Cdn Hunter Elmworth	8.35	5.56	2.21	0.58
AB-GP-1351	Esso Elmworth	4.96	2.45	1.03	1.48
AB-GP-1360	Hanlan (Banshee)	13.59	0.67	4.05	8.87
AB-GP-1458	Brazeau River	9.89	0.92	1.40	7.57
AB-GP-1520	Wembley	9.76	2.13	2.43	5.20
AB-GP-1522	Hamburg	4.61	0.00	0.51	4.10
AB-GP-1662	Caroline	17.01	2.25	0.40	14.36
Plant Types					
1		5.99	3.34	2.35	0.30
2		6.52	1.04	1.68	3.80
3		6.24	1.41	1.18	3.65
4		12.16	2.03	1.66	8.47
5		15.78	1.55	2.41	11.82

Designated Facilities

The following are the Designated Facilities at January 1, 1995 (please refer to Section 16.3) together with the 1995 Unit Operating Cost Rates (UOCR) and the delayered UOCR for each.

			DELAYERED RATES		
EUB FACILITY NUMBER	FACILITY NAME	FACILITY $\$/10^3\text{m}^3$ UOCR	COMPRESSING $\$/10^3\text{m}^3$ UOCR	GATHERING $\$/10^3\text{m}^3$ UOCR	PROCESSING $\$/10^3\text{m}^3$ UOCR
1002	NEVIS	10.92	2.42	2.88	5.62
1004	HOMEGLEN-RIMBEY	8.81	2.79	2.14	3.88
1020	CARSTAIRS	15.49	5.14	1.81	8.54
1022	CESSFORD	-0.08	0.00	-0.03	-0.05
1034	WINDFALL	10.80	1.82	4.31	4.67
1037	JUMPING POUND	1.48	0.01	0.25	1.22
1042	KARR	10.13	0.41	4.01	5.71
1045	BONNIE GLEN	-1.06	0.00	-0.02	-1.04
1047	MINNEHIK-BUCK LAKE	16.49	2.74	3.63	10.12
1050	CROSSFIELD	10.36	0.81	1.62	7.93
1054	WILDCAT HILLS	5.21	0.67	0.48	4.06
1056	WATERTON	7.94	0.92	0.94	6.08
1058	KAYBOB	14.22	1.96	5.89	6.37
1060	HARMATTAN ELKTON	12.29	1.91	0.91	9.47
1069	JUDY CREEK	11.00	3.48	0.65	6.87
1074	BONNIE GLEN	-1.06	0.00	-0.02	-1.04
1079	CROSSFIELD EAST	40.56	1.69	13.59	25.28
1084	EDSON	10.80	1.82	4.31	4.67
1097	GHOST PINE	10.92	2.42	2.88	5.62
1105	RAINBOW	5.70	0.00	0.24	5.46
1107	KAYBOB SOUTH	14.22	1.96	5.89	6.37
1108	BRAZEAU RIVER	13.27	3.66	2.69	6.92
1131	BURNT TIMBER	10.67	1.22	2.53	6.92
1132	MARTEN HILLS	10.42	3.98	4.48	1.96
1133	STRACHAN	29.79	2.88	7.95	18.96
1141	STRACHAN	1.91	0.18	0.48	1.25
1144	KAYBOB SOUTH	16.06	2.44	3.57	10.05
1147	SINCLAIR	5.90	3.30	1.01	1.59
1169	DUNVEGAN	6.93	1.89	3.38	1.66
1173	RICINUS	3.55	0.92	0.64	1.99
1292	WAPITI	1.28	0.67	0.34	0.27
1350	ELMWORTH	6.17	4.39	1.23	0.55
1351	ELMWORTH	3.43	1.33	0.93	1.17
1360	HANLAN (BANSHEE)	6.57	0.29	1.45	4.83
1458	BRAZEAU RIVER	12.97	1.17	1.80	10.00
1520	WEMBLEY	6.74	1.59	1.93	3.22
1522	HAMBURG	4.02	0.00	0.38	3.64
1662	CAROLINE	15.61	2.08	1.79	11.74
Plant Types					
1		5.85	3.26	0.30	2.29
2		6.29	1.00	3.67	1.62
3		3.73	0.84	2.19	0.70
4		11.61	1.93	8.10	1.58
5		9.07	0.89	6.80	1.38

Facilities by Reconciliation Facility Group

The following is a list of the EUB facilities tied to their respective Reconciliation Facility Group. Also included are all the Designated Facilities and their corresponding Plant Types: (*=Designated Facility).

Recon Group	EUB Facility	Plant Type
1002	1002*	5
	1097*	2
	1109	4
	1345	2
	1573	2
	2205	1
	2223	1
	2356	1
	2741	1
	2832	1
	2834	1
	2944	1
	2971	1
	2973	1
	3349	1
	3424	1
	3436	1
	3564	1
	3565	1
	3566	1
	3567	1
	3568	1
	3569	1
	3570	1
	3571	1
	3572	1
	3581	1
	3588	1
	3691	1
	3707	1
	3970	1
	3972	1
1004	1004*	5
	1013	4
	1061	2
	1130	4
	1263	2
	3236	1
	3698	1
	3793	1
	4011	1
	4100	1
-	1020*	5
-	1022*	2
1034	1034*	5
	1084*	5
-	1037*	5
-	1042*	2
1045	1045*	5
	1074*	4
	2234	1
	2641	1
1047	1047*	5
	1159	2
	3905	1
-	1050*	5
-	1054*	5
-	1056*	5
1060	1060*	5
	1090	2
1069	1069*	4
	1803	STRADDLE
	2297	1
	2437	1
	2438	1
	2439	1
	3576	1
	4036	1
-	1079*	5
1105	1105*	5
	2459	1
-	1108*	5
1120	1058*	4
	1107*	5
	1120	3
	1326	2
	1403	2
	2746	1
	3421	1
	3442	1
	3913	1
-	1131*	5
1132	1132*	3
	4093	1
-	1133*	5
-	1141*	5
1144	1144*	5
	1806	STRADDLE
-	1147*	5
1169	1169*	2
	1641	4
	1645	2
	2505	1
-	1173*	2
-	1292*	2
1350	1350*	2
	1802	STRADDLE
-	1351*	2
-	1360*	5
-	1458*	5
1502	1520*	5
	1805	STRADDLE
-	1522*	2
-	1662*	5

NOTE: NOT ALL THE DESIGNATED FACILITIES ARE TIED TO A RECON GROUP.

Designated Facilities

The following are the Designated Facilities at January 1, 1994 (please refer to Section 16.3) together with the 1994 Unit Operating Cost Rates (UOCR) and the delayered UOCR for each.

			DELAYERED RATES		
EUB FACILITY NUMBER	FACILITY NAME	FACILITY $/10^{3}m^3 UOCR	COMPRESSING $/10^{3}m^3 UOCR	GATHERING $/10^{3}m^3 UOCR	PROCESSING $/10^{3}m^3 UOCR
1002	NEVIS	14.96	3.88	7.85	3.23
1004	HOMEGLEN-RIMBEY	11.04	3.43	5.52	2.09
1020	CARSTAIRS	15.85	5.19	8.83	1.83
1022	CESSFORD	14.49	0.00	12.70	1.79
1034	WINDFALL	10.82	1.83	5.89	3.10
1037	JUMPING POUND	14.42	2.01	10.30	2.11
1042	KARR	6.14	0.08	2.97	3.09
1045	BONNIE GLEN	11.79	0.00	11.53	0.26
1047	MINNEHIK-BUCK LAKE	12.71	2.01	8.30	2.40
1050	CROSSFIELD	19.12	0.90	15.35	2.87
1054	WILDCAT HILLS	14.05	1.33	11.16	1.56
1056	WATERTON	16.39	1.21	13.61	1.57
1058	KAYBOB	12.20	1.86	6.70	3.64
1060	HARMATTAN ELKTON	9.35	1.19	7.63	0.53
1069	JUDY CREEK	11.43	3.29	7.25	0.89
1074	BONNIE GLEN	11.79	0.00	11.53	0.26
1079	CROSSFIELD EAST	20.58	1.67	12.82	6.09
1084	EDSON	10.82	1.83	5.89	3.10
1097	GHOST PINE	14.96	3.88	7.85	3.23
1105	RAINBOW	7.37	0.00	6.70	0.67
1107	KAYBOB SOUTH	12.20	1.86	6.70	3.64
1108	BRAZEAU RIVER	14.79	4.71	6.94	3.14
1131	BURNT TIMBER	14.88	2.06	8.88	3.94
1132	MARTEN HILLS	5.34	2.42	0.96	1.96
1133	STRACHAN	13.77	1.21	9.50	3.06
1141	STRACHAN	9.80	0.99	6.74	2.07
1144	KAYBOB SOUTH	10.50	0.71	7.23	2.56
1147	SINCLAIR	7.07	2.72	2.96	1.39
1169	DUNVEGAN	7.38	1.51	3.23	2.64
1173	RICINUS	4.31	1.26	2.31	0.74
1292	WAPITI	3.47	1.62	0.88	0.97
1350	ELMWORTH	4.88	3.27	0.68	0.93
1351	ELMWORTH	5.16	2.41	1.65	1.10
1360	HANLAN (BANSHEE)	9.86	0.33	7.53	2.00
1458	BRAZEAU RIVER		AVAILABLE FROM OPERATOR		
1520	WEMBLEY	9.46	2.21	5.48	1.77
1522	HAMBURG	2.34	0.00	2.10	0.24
1662	CAROLINE	17.91	4.12	12.53	1.26
Plant Type					
1		6.96	3.82	0.37	2.77
2		8.83	1.41	5.15	2.27
3		9.50	2.14	5.54	1.82
4		11.04	1.86	7.69	1.49
5		19.62	1.93	14.87	2.82

The following account codes are used by the Alberta Department of Resource Development:

ACCOUNT CODE	ACCOUNT DESCRIPTION
COK	Coke Royalty - Synthetic Oil
COL	Coal Royalty
CPR	Compensatory Petroleum Royalty
CPS	Syncrude Custom Processing
CSR	Commercial Oil Sands Royalty
EOR	Enhanced Oil Recovery
ESR	Experimental Oil Sands Royalty
FGR	Farm Gas Royalty
GAS	Natural Gas and Gas Products Royalty (Pre-1994)
G94	Natural Gas and Gas Products Royalty (Post-1993)
MET	Syncrude Metallic Royalty
MTC	Mineral Tax Certificates
MTX	Mineral Rights Tax
OGR	Override - Gas Royalty
OPR	Override - Oil Royalty
OSO	Oil Sands Other Royalty
PCR	Petroleum Condensate Royalty
PMC	Alberta Petroleum Marketing Commission
PMR	Mining Sundry Royalty
PRI	Petroleum Royalty Misc.
PSR	Primary Oil Sands Royalty
QRR	Quarrying Royalty
SC1	Syncrude Crude Oil Sands Royalty - 1
SC2	Syncrude Crude Oil Sands Royalty - 2
SC3	Syncrude Crude Oil Sands Royalty - APMC
SLR	Salt Lease Royalty
SSR	Sodium Sulphate Royalty
SU1	Sulphur Royalty - 1
SU2	Sulphur Royalty - 2
TPO	Trespass - Oil

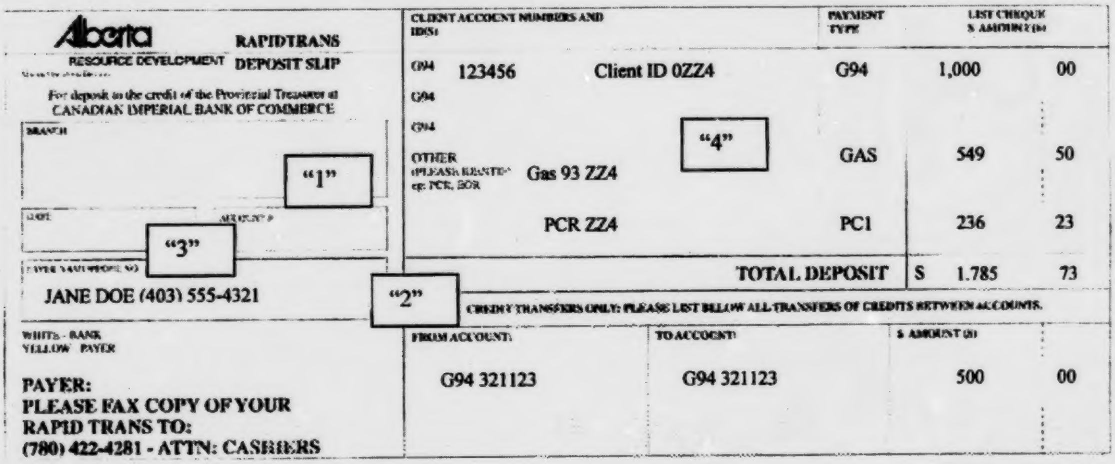
Rapidtrans Deposit Slip

The unique bank account number must be shown on the Rapidtrans Deposit Slip each month. The account number is entered in the area marked "1" shown on the following example of the Rapidtrans Deposit Slip form. The Rapidtrans Deposit Slip contains two copies. The original copy is retained by the CIBC branch and the bottom copy is retained by the company. Royalty payers are required to fax a copy of this deposit slip to the Financial Services Division Cashiers at fax number (780) 422-4281.

A separate field on the Rapidtrans Deposit slip has been provided for credit transfers. The "From Account" and "To Account" must be entered in the area marked "2" shown on the Rapidtrans Deposit Slip example.

Field "3" has been expended to include both the payer name and phone number. This will assist the cashiers in contacting the payer should any information provided on the Rapidtrans Deposit Slip remain unclear.

The final change is the pre-printed area, included under the "Client Account Numbers and Name(s) section, marked "4". This will prompt each payer to include the G94 account number when making their remittance, along with their client ID. Please ensure all other payment types are identified as required.



Alberta
RESOURCE DEVELOPMENT
RAPIDTRANS DEPOSIT SLIP

For deposit to the credit of the Provincial Treasurer at
CANADIAN IMPERIAL BANK OF COMMERCE

BRANCH "1"

DATE "3" ACCOUNT #

PAYER NAME/PHONE NO
JANE DOE (403) 555-4321

WHITE - BANK
YELLOW - PAYER

PAYER:
PLEASE FAX COPY OF YOUR
RAPID TRANS TO:
(780) 422-4281 - ATTN: CASHIERS

CLIENT ACCOUNT NUMBERS AND ID(S)		PAYMENT TYPE	LIST CHEQUE $ AMOUNT(S)	
G94 123456	Client ID 0ZZ4	G94	1,000	00
G94				
G94	"4"			
OTHER (PLEASE IDENTIFY eg: PCR, SOR) Gas 93 ZZ4		GAS	549	50
PCR ZZ4		PC1	236	23
	TOTAL DEPOSIT		$ 1.785	73

"2" CREDIT TRANSFERS ONLY: PLEASE LIST BELOW ALL TRANSFERS OF CREDITS BETWEEN ACCOUNTS.

FROM ACCOUNT:	TO ACCOUNT:	$ AMOUNT (S)	
G94 321123	G94 321123	500	00

Rapidtrans Deposit Location Changes

This is specific **only** to clients who make payments using the Departments generic account 09-35603. The generic account is primarily used for transition prior to the assignment of a unique account number, or to make a payment at a location other than the one specific to their unique account number. **Clients who have a unique account number other than 09-35603 must continue to use it at the related branch location.**

Location	Transit#	Bank Address	City
00001	00059	Jasper Avenue & 100th Street	Edmonton
00018	00009	CIBC Place, Bankers Hall, 309 8th Avenue	Calgary
00023	08009	Bow Valley Square 2	Calgary

Pre-Authorized Automatic Debit Payments

This process can be used for activities that have a specified payment due date of the last day of the month. (e.g., Gas Royalty and Condensate payments.)

All clients who elect to participate must sign a contract agreement with the Department. The client specifies in the contract the bank account number that the Department is authorized to automatically debit payments.

Clients must submit a completed contract by the 15th of the month in which they wish to begin automatic debit payments. Copy of the contract agreement is included at the end of this appendix.

Banking information provided in the agreement is confidential and only for the use of an authorized representative of the Department of Resource Development.

Each month the client must complete the Automatic Debit Remittance Form by the 5th last Government business day of each month prior to the operational due date of the invoice. The Remittance Form specifies the amount to be automatically debited. A signed contract agreement must be completed prior to submitting the Automatic Debit Remittance Form.

The Department will not arbitrarily debit a client's account without the client specifying the amount on the Automatic Debit Remittance form. This form must be completed for each month a payment is made by automatic-debit, as the Department of Resource Development will not automatically debit the Statement of Account balance.

A request can also be made by email, provided all the information that appears on the Automatic Debit Remittance form is included in the email request, such as Client Id, account number, total amount to be debited and amounts to be applied to each account. The email address is G94Deposit@enr.gov.ab.ca. The Automatic Debit Remittance form can be found in Appendix P.

It is important to note that any requests received subsequent to the 5th last Government business day of the month will not be processed until the last day of the following month.

RESOURCE DEVELOPMENT

Corporate Services
Financial Services

12th Floor
North Tower, Petroleum Plaza
9945-108 Street
Edmonton, Alberta T5K 2G6

Telephone 780/427-3600
Fax 780/422-4281

File No.

Date

«Company»
«Address1»
«Address2»
«City», «Province»
«PostalCode»

«Attention»

Dear Sir or Madam:

Kindly indicate by your signature on this Pre-Authorized Automatic Debit Payment Agreement that you accept the following terms, statements and conditions as being contractually binding upon you as the Client and Her Majesty the Queen in right of Alberta as represented by the Minister of Resource Development (herein called "DRD"):

1. That in this Agreement:

   (a) "Automatic Debit" means the automatic debiting of the Subject Bank Account for and in the amount of Specified Charges directed by the Client;

   (b) "Automatic Debit Remittance" means the form in Schedule "A";

   (c) "Business Day" means a work day for employees of the Crown in right of Alberta;

   (d) "Client" means the payor on record with the Crown in respect of the Charges that is identified in the Automatic Debit Remittance and that is signing this Agreement;

   (e) "Charges" means billings or invoices by DRD to the Client in respect of

      (i) royalty on Crown minerals,

      (ii) gas or petroleum accounts, and

      (iii) primary and experimental oil sands accounts, that are due and payable at the end of a month;

(f) "Operational Due Date" means the end of the month on which Charges are due and payable, if that day is a Business Day, or, if that day is not a Business Day, the first Business Day after that day;

(g) "Specified Charges" means the Charges of the kinds or types and in the amounts specified in the Automatic Debit Remittance;

(h) "Subject Bank Account" means the bank account the details of which are described and set forth in section 7 of this Agreement.

2(1) That Schedule "A" attached and headed "Automatic Debit Remittance" is hereby incorporated into and made part of this Agreement and any reference herein to "Agreement" shall be deemed to include that Schedule.

(2) That in this Agreement words in the singular include the plural and words in the plural include the singular.

(3) That in this Agreement a reference to the *Mines and Minerals Act* shall be construed as a reference to

(a) that Act, as amended from time to time,

(b) any replacement of all or part of that Act from time to time enacted by the Legislature, as amended from time to time, and

(c) any regulations, orders, or other subordinate legislation or directives or information letters from time to time made under any enactment referred to in clause (a) or (b), as amended from time to time.

(4) That this Agreement shall be construed, interpreted and applied in accordance with the laws and in the Courts of the Province of Alberta.

(5) That if there is any conflict between the provisions in the body of this Agreement and the Schedules of this Agreement, the provisions in the body of this Agreement shall prevail.

(6) That if any provision of this Agreement is declared by a court of competent jurisdiction to be unlawful, invalid or unenforceable, it shall not affect the validity or enforceability of any other provision of this Agreement.

3. That participation by the Client in the programme for payment by Automatic Debits is conditional upon the Client signing this Agreement which pre-authorizes payments by Automatic Debit.

4. That once the Client has signed this Agreement the Client can, by following the requirements of section 5 of this Agreement, make it applicable to all or any portion of a Charge by DRD to the Client made subsequent to the signing of this Agreement.

5. That this Agreement will be made applicable to all or any portion of a Charge by DRD to the Client through an election by the Client to pay Specified Charges by Automatic Debit. The Client may elect to pay Specified Charges by Automatic Debit by

   (a) submitting to DRD by facsimile, by email or by registered mail a fully completed Automatic Debit Remittance in the form in Schedule "A" setting forth the Specified Charges to be paid by Automatic Debit, and

   (b) ensuring that DRD receives the Auto Debit Remittance not less than 5 Business Days before the Operational Due Date.

6. That if the Client makes an election in accordance with section 5 to pay Specified Charges by Automatic Debit,

   (a) this Agreement will constitute and can be used as authority for DRD to electronically debit the Subject Bank Account in the amount of those Specified Charges, and

   (b) each such Debit will be treated by DRD and the Client and will have the same effect and consequence at law as if the Client had issued a cheque instructing the bank to pay the amount of the Debit to DRD.

7. That the Client having elected under section 5 to pay by Automatic Debit, hereby directs that the Automatic Debit be made against the following bank account:

   Bank:
   Branch Address:
   Phone Number:
   Account Name:
   Account Number:
   Transit Number:

   and agrees to provide a void cheque for verification purposes.

8. That the payment of, and any default in the payment of, Specified Charges by Automatic Debit shall be governed by and subject to the *Mines and Minerals Act* just as if the Client had elected to pay those Charges by cheque or by any other method of payment.

9. That the Client shall notify DRD in accordance with section 11 of this Agreement of any changes to the information contained in the body or in Schedule "A" of this Agreement not less than 5 days prior to the making of any election under section 5 that is affected by those changes or to which those changes may relate.

10. That DRD may periodically review and update the Auto Debit Remittance in Schedule "A" of this Agreement. When a form in a Schedule of this Agreement is updated, the Schedule will be deemed to consist of the updated form from the time of its creation until such time as a further update, if any, is made to the form. DRD will advise the client of each update to the Auto Debit Remittance in Schedule "A".

11. That all notices, statements, submissions or other communications required or permitted to be given or made by the Client to DRD under this Agreement shall be deemed given or made to DRD if in writing and either personally delivered to DRD or sent by registered mail, postage prepaid, or by facsimile or email transmission, charges prepaid, to DRD at the following address:

Department of Resource Development
Financial Services
12th Floor, Petroleum Plaza, North Tower
9945 – 108 St.
Edmonton, AB T5K 2G6

Contact Name: Yasmin Suleman
Phone Number: (780) 422-5860
Fax Number: (780) 422-4281

12. That DRD or the Client may terminate this Agreement upon 60 days' notice to the other Party given in accordance with section 11 of this Agreement.

____
For the Minister of Resource Development on behalf of Her Majesty

Above terms, conditions and statements accepted
and agreed to by ____________________________

[Corporate Seal]

Per: ____________________________
Position Held: ____________________________

Per: ____________________________
Position Held: ____________________________

Date: ____________________________

THIS IS SCHEDULE "A" ATTACHED TO AND FORMING PART OF THE AGREEMENT MADE BETWEEN HER MAJESTY THE QUEEN IN RIGHT OF ALBERTA AS REPRESENTED BY THE MINISTER OF RESOURCE DEVELOPMENT AND ____________________ ON ________, _____.
(NAME OF CLIENT) (DATE)

Alberta
DEPARTMENT OF RESOURCE DEVELOPMENT
Financial Services Division

Automatic Debit Remittance

12th Floor Building
Street Address
City, Alberta Postal Code

DATE: ________________ **TOTAL TO BE DEBITED:** ______________________

Auto Debit to the credit of the Provincial Treasurer for:

Royalty Client Name: ____________________________________

Royalty Client ID: ___________

Gas Royalty Account Number: *G94* ____________ Amount: ____________

G94 ____________ Amount: ____________

G94 ____________ Amount: ____________

Other (*please specify account number/activity ID* E.g.: PCR 123, OSR 123, EOR 123):

Account #________________ Amount: ____________
Account #________________ Amount: ____________
Account #________________ Amount: ____________
Account #________________ Amount: ____________

Chief Financial Officer (*please print*): ____________________

Chief Financial Officer Signature: ______________________

Contact Number: ______________________

NOTE: The Department of Resource Development MUST receive this form on or before the 5th last working day of the month. Remittance forms received on the 5th last working day will have funds debited from your bank account the night of the operational due date of the current Invoice. Forms received late will be processed on the last day of the next month. NOT TO BE USED FOR CREDIT TRANSFERS.

PAYER:

PLEASE FAX COPY OF YOUR AUTO DEBIT REMITTANCE TO:
780/ 422-4281 ATTN: CASHIERS or

MAIL to: Financial Services
9945 108 Street
Edmonton, Alberta T5K 2G6

1. Gas Royalty – Client Services Help Desk

Alberta Department of Resource Development
Gas Royalty Operations
8th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 427-2962
Fax: (780) 427-3334 or (780) 422-8732

2. Account Inquiries

Alberta Department of Resource Development
Accounts Control
8th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 422-7184 (780) 422-7232
(780) 422-7185 (780) 415-1304
(780) 422-7186
Fax: (780) 427-3334 or (780) 422-8732

3. Supplies: Reporting Forms

Alberta Department of Resource Development
Calgary Information Centre
Monenco Place.
801 - 6th Avenue SW
Calgary, Alberta T2P 3W2
Telephone: (403) 297-8955
Fax: (403) 297-8954

...or...

Alberta Department of Resource Development
Gas Royalty Operations
8th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 427-2962
Fax: (780) 427-3334 or 427-8732

4. Supplies: Energy Statutes & Regulations

Queen's Printer Bookstore
Main Floor, McDougall Centre
455 - 6th Street SW
Calgary, Alberta T2P 4E8
Telephone: (403) 297-6251
Fax: (403) 298-8450
(Also available on disk and online)

...or...

Queen's Printer Bookstore
11510 Kingsway Avenue
Edmonton, Alberta T5G 2Y5
Telephone: (780) 427-4952
Fax: (780) 452-0668

5. Revenue Audit inquiries

Alberta Department of Resource Development, Field Audit
Monenco Place
801 - 6 Avenue SW 4th Floor
Calgary, Alberta T2P 3W2
Telephone: (403) 297-8955
Fax: (403) 297-5199

6. Appeals and Advance Rulings Inquiries

Alberta Department Resource Development
Interpretation and Rulings Branch
14th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 422-6029
Fax: (780) 422-0975

7. Energy Resources Acts and Regulations

Alberta Energy and Utilities Board
Information Services
640 - 5th Avenue SW
Calgary, Alberta T2P 3G4
Telephone: (403) 297-3744
Fax: (403) 297-2147

8. Computer-generated data submissions CIBC rapidtrans (royalty payment) deposit slips

Alberta Department of Resource Development
Gas Royalty - Client Services
8th Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 427-296[illegible]
Fax: (780) 427-3334 or 422-8732

...or...

Alberta Department of Resource Development
Calgary Information Centre
Monenco Place.
801 - 6th Avenue S.W.
Calgary, Alberta T2P 3W2
Telephone: (403) 297-8955
Fax: (403) 297-8954

9. Information Letters

Alberta Department of Resource Development
Minerals Tenure
2nd Floor, North Petroleum Plaza
9945 - 108 Street
Edmonton, Alberta T5K 2G6
Telephone: (780) 422-9429 Fax: (780) 422-1123

10. Financial Services (Cashiers)

Alberta Department of Resource Development
Corporate Services
12th Floor, North Petroleum Plaza
9945- 108 Street
Edmonton, Alberta T3K 2G6

Telephone: (780) 427-3600 Fax: (780) 422-4281

NOTE: ALL ROYALTY CLIENTS IN ALBERTA CAN DIAL 310-0000 TO GET ACCESS TO ANY GOVERNMENT DEPARTMENT WITHIN THE PROVINCE.
ROYALTY CLIENTS LOCATED IN CALGARY CAN DIAL (403) 297-6161.

1. Information Sources

Following are sources for information relating to the assessment, levy and collection of Alberta Crown natural gas royalties.

Addresses and telephone numbers for groups to contact within the Alberta Department of Resource Development and the Alberta Energy and Utilities Board can be found in *Appendix L.*

Legislation

DEPARTMENT OF RESOURCE DEVELOPMENT ACT

MINES AND MINERALS ACT

ALBERTA AVERAGE MARKET PRICE REGULATION

COMPENSATORY ROYALTY REGULATION

EXPLORATORY DRILLING ASSISTANCE REGULATIONS

EXPLORATORY DRILLING INCENTIVE REGULATIONS

GENERAL REGULATION

GEOPHYSICAL ASSISTANCE REGULATIONS

GEOPHYSICAL INCENTIVE PROGRAM REGULATIONS

NATURAL GAS ROYALTY REGULATION, 1994

PETROLEUM AND NATURAL GAS AGREEMENTS REGULATION

NATURAL GAS MARKETING ACT

NATURAL GAS MARKETING REGULATION

NATURAL GAS PRICE ADMINISTRATION ACT

NATURAL GAS PRICING ADMINISTRATION REGULATION

TAKE-OR-PAY COST SHARING ACT

TAKE-OR-PAY COST SHARING REGULATION

The Alberta Department of Resource Development offers a publication, in binder form, containing Acts and Regulations pertaining to the management of Alberta mineral resources. Inquiries concerning subscription to this publication should be directed to Queen's Printer Bookstore at the address noted in *Appendix L.*

Information Letters and Bulletins

Information Letters are published periodically by the Alberta Department of Resource Development to registered subscribers. These letters deal with changes to Department policies and practices concerning subjects such as oil sands, coal, drilling, environmental concerns, incentives, petroleum and natural gas, licenses, leases and royalties. *Information Letters* are also the official publication of monthly royalty factors and natural gas reference prices. To be added to the mailing list, contact Alberta Department of Resource Development, Minerals Tenure, at the address noted in *Appendix L.*

Information Bulletins are published periodically by the Alberta Department of Resource Development to provide information on a broad range of topics. Among them are:

- monthly and annual natural gas royalty variables *(par prices, reference prices and other matters);*
- interest rates *(applied to Crown royalties)*;
- filing deadlines and reminders for required reporting; *and*
- year-end close-out information (pre-1994).

Gas *royalty clients* automatically receive *Information Bulletins*. Other interested parties may be placed on the mailing list by contacting the Gas Royalty Branch at the address noted in *Appendix L.*

The following terms are defined in the context of *the Natural Gas Royalty Regulation,* 1994 *(Alberta Regulation 351/93)* and the ALBERTA NATURAL GAS ROYALTY PRINCIPLES AND PROCEDURES manual, of which they are a part.

A word or term that is shown in ***bold italics*** indicates a definition taken from the ***Regulation.*** A word or term that is shown in **bold** indicates a working definition applicable to the **Principles and Procedures manual.**

Acid Gas is natural gas containing hydrogen sulphide and carbon dioxide.

Act means the Mines and Minerals Act.

Advance Ruling is a statement by the Department as to how it will interpret the applicable laws, policies and guidelines with respect to certain proposed business arrangements.

Aggregator means a company which contracts for natural gas supplies from a number of producers, establishing a supply pool from which it supplies gas to downstream customers. A company may be considered an aggregator for special requirements of the Resource Development Ministry.

Alberta Energy Utilities Board (EUB) is jointly funded by industry and the Alberta Government. Part of the EUB mandate is to ensure that Alberta's energy resources are exploited with due consideration to sound technical and conservation principles.

Allocated volumes means volumes of natural gas and gas products allocated to an outlet owner on an Owner Activity Statement (OAS).

Allowable costs means costs and allowances for which the Crown is liable under Section 17(1) of the Regulation.

Allowable capital costs means the costs and allowances for which the Crown is liable under Section 17(1) of the Regulation.

Allowable operating costs means the operating and working capital portion of the costs from which the Crown liable allowances are calculated (Section 17(1) of the Regulation).

Appeals process means a process established by the Department to address disagreements between royalty clients and the Department.

ARTC means the Alberta Royalty Tax Credit Program as amended from time to time.

Arm's-length For the purpose of the provisions of the Regulation that refer to persons dealing at arm's-length with each other, persons shall be regarded as not dealing at arm's-length with each other if, at a material time under the Regulation, they are related parties within the meaning of the CICA Handbook published from time to time by the Canadian Institute of Chartered Accountants. (Refer to sections 3050, 3055, and 3840 in the CICA Handbook.)

Associate, in the context of gas and gas product valuation, refers to a person who is associated with another person.

Associated, in the context of gas valuation, refers generally to a relationship between persons where, directly or in combination with other associates, one person owns or has a beneficial interest equal to or greater than 75% of the other person.

Average daily production means the natural gas obtained in a month of a gas well in thousands of cubic metres divided by the number of hours of operation of the well in the month and multiplied by 24.

Base royalty rate means "old gas royalty rate" based on the formula provided in the Regulation for calculating old gas royalty rate.

Battery means a pipeline or pipeline installation at which natural gas recovered from one or more wells is collected and measured prior to its delivery into a gathering system

Billing period means the production year and month to which the current charges and credit for Crown royalty apply.

Board means the Alberta Energy and Utilities Board.

Broker is a person(s) other than a Local Distribution Company (LDC) that brings together buyers and sellers of gas and may or may not take title to the gas. Thus, the *broker* acts as an agent or consultant.

Brokered capacity means the right of a party to transport natural gas or a gas product on a transportation system, where all or a portion of that right is sold, exchanged or otherwise provided to another party.

Business Associate is a client, external agency or industry group of significance with which information is exchanged.

Butane, in addition to its normal scientific meaning, means a mixture mainly of butane which ordinarily may contain some propane or pentanes-plus.

By-product means an unsold, processed product stream consisting of a new product, which is created as the result of processing an existing product(s). *By-product* streams can exist in any form (i.e. gas, liquid, solid). A product stream changes from *production* or gas to *by-product* at the processing point where the new product is created from the existing product(s).

CAP – see Corporate Average Price.

Capital cost allowance means the sum of retirement, depreciation and return on average capital.

Cascade facility means an upstream facility to which volumes are allocated by the downstream facility operator.

CERR - Corporate Effective Royal Rate.

Charge types means the types of charges reported on the Crown Royalty Detail Calculation and Volumetric statements. The charge types consist of Crown royalty, Injection Credits, Enhanced Oil Recovery Operation Cost Adjustment, Crown Royalty Paid Bank Settlement, Crown Royalty Inventory Settlement and Provisional Royalty Assessments.

Co-existent gas means gas that is recovered from a production entity and which is partly new gas and partly old gas.

Co-generation means concurrent production of usable forms of energy from a single fuel source using electricity and thermal and/or mechanical energy.

Co-generation contract, in relation to gas valuation, means a contract for the sale of gas to a co-generation facility.

Co-mingled, with respect to streams of natural gas or of one or more gas products, means streams that are not separated from each other and are produced from/transported through the same production/transportation facilities at the same time.

Collateral agreement means an agreement that is additional to and has a bearing on the terms or conditions of another agreement.

Commercial oil sands scheme means a scheme or operation approved by the EUB under the Oil Sands Conservation Act to produce oil sands or crude bitumens, and that is not subject to royalties under the Experimental Oil Sands Royalty Regulation or the Petroleum Royalty Regulation.

Commercial storage facility means the wells and other facilities used in the operation of a commercial storage scheme and designated by the Minister as a **commercial storage facility*** for the purposes of the Regulation.

Commercial storage scheme means a scheme approved or ordered by the Board under the Oil and Gas Conservation Act for the storage of natural gas or a gas product in an underground formation or subsurface cavern, and designated by the Minister as a commercial storage scheme for the purposes of the Regulation.

Compensatory royalty is one of the options available to a person that has been served with an offset notice respecting a Crown lease.

Compensation factor, in relation to unit operating cost rates, is intended to address the overall impact to the Crown and industry from the change in calculating the Crown share of Operating Cost Allowance.

Compliance mechanism means administrative procedures, including the calculation of penalty and royalty charges, used by the Alberta Department of Resource Development to encourage prompt and accurate reporting by industry and to ensure royalties due to the Crown are fully collected.

Condensate means a mixture of mainly pentanes-plus and heavier hydrocarbons that may be contaminated with sulphur compounds, which is recovered or is recoverable at a well from an underground reservoir, and that may be gaseous in its virgin reservoir state but is liquid at the conditions under which its volume is measured or estimated.

Consumption means use of natural gas and gas products as a fuel.

Corporate Average Price (CAP), in relation to a royalty client and a year, means the corporate average price for gas established for the royalty client for that year, pursuant to Schedule 1 of the Regulation.

Corporate effective royalty rate is the royalty client's weighted average royalty rate that determines the portion of the royalty client's Crown share of Capital Cost Allowance and Crown share of Custom Processing Cost Allowance that the Crown will deduct in respect of a production year.

Corporate gas factor is the factor that, when multiplied by the Gas Reference Price for a month, determines the price at which the monthly Crown royalty share of gas is valued for a royalty client that has a valid CAP election.

Corporate signing officer means a person who is authorized to sign for the corporation

Crown means Crown in the right of Alberta.

Crown interest share means the quantity of gas or gas products that is attributable to the gas produced and recovered from a well event that is subject to a Crown lease agreement.

Crown lease means an agreement granting petroleum and natural gas rights, or natural gas rights or petroleum rights only.

Crown percentage means the portion of the production from well events in the Well/Well Group/Unit/Injection Scheme that is recovered pursuant to a Crown lease, as shown in the records of the Department

Crown royalty detail means the Crown Royalty Detail statement provided by the Department in support of the monthly Corporate Invoice.

Crown royalty rate means the percentage derived through a formula prescribed in Regulation. It is used to determine Crown royalty share.

Crown royalty share means the quantity determined when the Crown interest share of gas or a gas product is multiplied by the Crown royalty rate for that gas or gas product.

Crown royalty volumes means the actual volumes of gas and gas products on which Crown royalty compensation is finally assessed.

Crown share of custom processing cost allowance means that portion of a royalty client's net custom processing fees paid in a production year that will be deducted by the Crown for that production year.

Custom processing means gathering and/or compressing and/or processing of gas where the person receiving the service is charged a fee by the person providing the service.

Custom processing adjustment factor means the factor that represents the proportion of the Capital Cost Allowance for a Facility Cost Centre that is deducted from the Capital Cost Allowance otherwise payable by the Crown to eliminate costs attributable to custom processing.

Custom processing fee means the fee paid by a custom user to the person providing a custom processing service.

Customer user means the person receiving a custom processing service.

Cycling means an injection of gas, usually residue gas, into a gas reservoir for the purpose of maintaining the pressure in the reservoir to increase the gas liquids recovered.

Cycling scheme means an injection of gas into an EUB-approved scheme for the purposes of cycling.

Deep Gas Royalty Holiday Program (DGRHP), means a program designed to partly compensate for the cost of the successful discovery and production of natural gas from deep gas pools.

Delayered unit operating cost rate means the portion of a Unit Operating Cost rate that applies to any one of the three components of that Unit Operating Cost rate, either gathering, compressing or processing.

Demand charge means a cost that is included in the total cost of service of a transportation system, and that is charged to a customer on the basis of service entitlement rather than actual use of the transportation system in a given period of time.

Department means the Alberta Department of Resource Development.

Depreciated asset means an asset included in Allowable Capital Cost which has been subject to the calculation of annual depreciation where that depreciation has been included in the Capital Cost Allowance of a Facility Cost Centre.

Designated aggregators means those aggregators chosen from the recognized aggregators by the Resource Development Ministry for special purposes.

Designated distributor means a local distribution company in Alberta, normally an Alberta gas utility, determined to be a Designated Distributor by the Ministry under the Natural Gas Marketing Regulation (358/86, as amended).

Designated facility means a facility classified as a designated facility for purposes of establishing a Unit Operating Cost Rate.

Designated purchaser means a person designated by the Minister as a major purchaser in Alberta of propane or butane, and who is directed to furnish information to the Department (*refer to Section 23(2) of the Regulation).*

Designated storer means a person who is an operator of natural gas liquids storage facility and who is designated by the Minister to furnish information to the Department (*refer to Section 23(2) of the Regulation).*

Dispose of, in relation to any natural gas and gas products, means disposition of a person who, as a result, becomes the owner of such products, e.g. sell, trade, exchange, give away, transfer, etc.

Disposed asset means an asset included in the Allowable Capital Cost of a Facility Cost Centre and which has been sold or otherwise disposed of.

EDI means Electronic Data Interchange.

End user means the person who is the ultimate user of gas or a gas product, whether as a fuel or in a manufacturing process.

Energy adjusted gas equivalent volume is the common unit of measure for gas and gas products in their gaseous form. This unit of measure also takes into consideration their heat contents.

Enhanced oil recovery (EOR) means an approved injection scheme, intended to increase the recovery of crude oil from a reservoir by the external application of physical and chemical processes that supplement naturally occurring or simple fluid injection processes.

Enhanced oil recovery (EOR) scheme is an Injection Scheme that is approved under the Enhanced Oil Recovery of Oil Royalty Reduction Regulation.

Enhanced recovery means increased recovery of crude oil and/or natural gas from a reservoir, which is achieved by the external application of physical or chemical processes that supplement naturally occurring or simple fluid injection processes.

Enhanced recovery scheme is an Injection Scheme that is approved under the Enhanced Recovery of Oil Royalty Reduction Regulation.

EPSTA fee means the standard fee specified in the Ethane Plus System Trading Agreement for the fractionation of natural gas liquids.

Ethane, in addition to its normal scientific meaning, is a mixture mainly of ethane which ordinarily may contain some methane or propane.

Ethane conversion rate means one cubic metre of liquid ethane = 0.28132 thousand cubic metres of gas.

EUB means the Alberta Energy and Utilities Board.

EUB Facility means a gas gathering system, or gas processing plant, that is approved by the EUB and is recognized by the Alberta Department of Resource Development as a facility where volumes are available for sale.

Excess Capacity Fee is a fee in dollars or in kind, which is specifically charged for those volumes in excess of ownership throughput capacity.

Excess Capacity Volumes are volumes processed by a functional unit (Facility Cost Centre) owner in excess of his working interest in the functional unit. (e.g. Company A owns 10,000 capacity, Company B own 10,000 capacity; Company A processes 15,000 volumes of which 5,000 are therefore excess capacity volumes.)

Exchange means a transaction where the parties exchange a quantity of gas or a gas product at one location for a quantity of gas or a gas product at another location (see also swap).

Exhibit A forms part of a Unit Agreement and describes each Tract, Tract participation, Royalty Owners, Working Interest Owners and each Working Interest Owner's share of Tract participation. It also summarizes each Working Interest Owner's Unit participation.

Experimental oil project means an experimental oil scheme approved by the EUB and designated by the Minister.

Ex-Alberta Gas LDC means a local gas distribution company located outside of Alberta, who removes gas from Alberta that is destined for resale in its franchise area under tolls and tariffs set by the local regulator.

Facility means

- a battery,
- a gathering system,
- a gas processing plant,
- a reprocessing plant,
- a **gas injection facility***, or
- a commercial storage facility.

Facility cost centre means an approved grouping of gathering and/or compression and/or processing facilities that have common ownership interests and the same Facility Operator.

Fee for service refers to a transaction in which one person provides a service to another person and charges that other person a fee for the service provided.

Field condensate means products obtained from natural gas or solution gas before it is delivered to a gathering system.

Field straddle plant means a reprocessing plant designated by the Minister as a field straddle plant for the purposes of the Regulation.

Flared, with respect to gas, means gas that is released in the atmosphere by burning or otherwise with no direct economic benefit derived.

Floor price, with reference to propane and butane, means the alternate unit value for the monthly reference price of either one of them.

Fractional allowance, with reference to the monthly Propane Reference Price, Butane Reference Price and Pentanes Reference Price, means the amount deducted from that reference price as part of the calculation of the price at which the Department will value the Crown royalty share of propane, butane or pentanes-plus that are subject to Crown royalty as a component of a NGL mix.

Fractional facility means a facility where NGL mix is separated into specification ethane, propane, butane and/or pentanes-plus.

Fractionation Plant means a plant that processes gas products but does not process residue gas.

Freehold lands means all lands in a province, and all rights thereto and interests therein, that are not Crown lands; lands other than Crown lands and other lands vested in Her Majesty.

Fuel gas means raw gas or residue gas that is consumed, prior to sale or other disposition, in the gathering, compressing or processing of natural gas or a gas product, that is owned by the owner of the gas or gas product that is so consumed.

Functional unit is a unit of an EUB facility. It is called a Facility Cost Centre (Post-1993 description) or a GCA facility (Pre-1994 description).

Gas means natural gas, residue gas or ethane. It is an unsold, processed product stream composed mainly of natural gas, which is left over after natural gas is processed (residue gas). Natural gas is processed in order to remove heavier components (natural gas liquids), hydrogen sulphide and/or other impurities from the gas. The residue is the portion of the original gas that remains after processing. A natural gas stream changes category from *production* to gas at the point where other products (by-products) are extracted from the gas.

Gas account means an account maintained by the Department for a royalty client pursuant to section 15(6) of the Regulation.

Gas injection facility means the wells and other facilities used by an operator in the operation of one or more **gas injection schemes***.

Gas injection scheme means a scheme, other than a commercial storage scheme, approved or ordered by the Board under the Oil and Gas Conservation Act and respecting the injection of natural gas or a gas product into an underground formation.

Gas lift means the raising or lifting of liquid from a well by means of injecting gas into the liquid in the well bore.

Gas par price is a factor used to calculate the Crown royalty rate in the price-sensitive formulae for Crown royalty on raw gas, residue gas and ethane. It is the previous month gas reference price.

Gas processing plant means a plant for the extraction from natural gas of a gas product but does not include a reprocessing plant, well head separator, treater or dehydrator.

Gas product means residue gas, ethane, pentanes-plus, sulphur, propane, butane or any other product obtained from natural gas by processing or reprocessing or otherwise, but does not include field condensate.

Gas select price, refer to either Old Gas Select Price or New Gas Select Price.

Gas well means (for royalty purposes) a well that produces natural gas from a pool or portion of a pool, either alone or with oil. Alberta Energy and Utilities Board establishes whether a well event is a gas well.

Gathering includes compressing by means of a compressor forming part of a gathering system.

Gathering system means a pipeline or pipeline system, including installations and equipment associated with the pipeline or pipeline system, that transmits natural gas from one or more wells to a gas processing plant or other delivery points.

Gigajoule (GJ) means one billion joules. A joule is a SI (metric) unit for measuring energy. It is the work done, or energy used, in applying one newton of force to move a body one metre.

Grandfathered contract means a contract in existence before January 1, 1994 for which the Minister has authorized the royalty client to value the Crown royalty share of gas delivered under the contract at the net price and/or net value of other considerations received under the contract.

Gross Crown royalty means the value of the Crown royalty share of production before any deduction for the Crown share of cost allowances.

Heat content means the total amount of heat contained in a gas stream.

Industry means the oil and gas industry.

Injection credit means a money credit applied to a royalty client's corporate account in respect of the Crown's royalty share of gas or a gas product injected into an injection scheme in a month.

Injection facility means an operating entity identified by the EUB and designated by a facility ID number. Injection activity carried on at such a facility consists of injecting gas and/or gas products into a reservoir for maintaining pressure, displacing liquids, or storage.

Injection scheme means a group of industry clients who participate in injection activity. East injection scheme is part of an injection facility. In some instances, multiple injection schemes are operating within an injection facility.

Intentional trespass means the trespasser wilfully and knowingly produced minerals from Crown rights without proper authorization.

Intra-Alberta transportation means transportation of gas or a gas product from one point in Alberta to another point in Alberta.

Invoice means a monthly invoice issued and sent to a royalty client pursuant to Section 15(1) of the Regulation for Crown natural gas royalty.

Joule means a unit of energy of work equal to the work done by a force of one newton magnitude when the point at which the force is applied is moved one metre in the direction of the force.

Large volume end-user means any end **user*** who (1) is capable of consuming 100,000 GJ of marketable gas per annum, and (2) uses the gas for industrial consumption, commercial consumption, shrinkage at a mainline straddle plant, or as fuel gas for these uses.

Lessee means a person who is granted rights under a Crown or other lease agreement.

Lessor means a person who owns the minerals and grants rights to another person under a Crown or other lease agreement.

Light ends means a gas product that is obtained at a gas processing plant or reprocessing plant and is, in the Minister's opinion, given by the owner of the product to the owner of the plant for no consideration because the product is not of a kind or quantity sufficient for the owner of the product to dispose of it by way of sale. For example, traces of excess ethane beyond specification in an NGL stream is a contaminant for which no value is received would be reported as light ends.

Long-term contract, in relation to grandfathering provisions under the Gas Reference Price, this means a contract for the sale of gas where the term of the contract is not less than 10 years.

Low productivity well allowance (LPWA) means a reduction in the Crown royalty rate for gas on account of low production rates in the well event from which the production is obtained.

Mainline straddle plant means a plant designated by the Minister as a mainline straddle plant.

Market value means the value given for a commodity in a transaction between a willing arm's-length seller and a willing arm's-length buyer.

Merger means the absorption of one company by a second company, such that the first company ceases to exist and the second company acquires the assets, liabilities, rights, obligations, etc., of the first company.

Natural gas means a combustible gas consisting of methane and other hydrocarbons.

Natural gas liquids means propane, butane and pentanes-plus or any one of them.

Natural succession means an event where royalty clients combine their businesses as a result of takeovers, mergers or amalgamations. It excludes purchase of a segment of one company by another.

Netback price means the price paid for gas or a gas product at a specified location, usually the location where the transfer of ownership takes place, after deduction of all costs incurred beyond the specified location.

Net book value means the Department's value of a capital asset after deduction of any depreciation calculated in respect of that asset.

Network – see Royalty network.

New Gas means natural gas that qualifies as new gas under Section 1 of Schedule 5 of the Regulation.

New gas select price, in relation to a production month, means the amount per gigajoule prescribed pursuant to Section 6(3)(a) of the Regulation as the new gas select price for the year in which the production month occurs. This price determines the level of royalty in the royalty rate formula.

New pentanes-plus means pentanes-plus that qualified as new pentanes-plus under Section 2 of Schedule 5 of the Regulation.

NGL means Natural Gas Liquid.

Nominal cost allowance, in relation to the reference price for raw gas, means a reduction in the price paid for the Crown royalty share in recognition of value not yet added by processing but which is reflected in the Gas Reference Price.

Non-arm's-length For the purpose of the provisions of the Regulation that refer to persons dealing at arm's-length with each other, persons shall be regarded as not dealing at arm's-length with each other if, at a material time under the Regulation, they are related parties within the meaning of the CICA Handbook published from time to time by the Canadian Institute of Chartered Accountants. (Refer to sections 3050, 3055, and 3840 in the CICA Handbook.)

Nova cost-of-service means the deduction from the Gas Reference Price for average cost of transportation from any point in Alberta to the border points where gas is exported from Alberta and to end users in Alberta. The calculation is made by dividing total Nova charges each month by Nova net billable receipts each month.

Nova gross billable receipts means the total receipt quantities that Nova bills for in a month. Fuel gas and measurement variance are included in this total.

Nova net billable receipts are Nova Gross Billable Receipts less fuel gas and measurement variance on the Nova system.

Novation means the substitution of a new contract or obligation for an existing one, where the only difference between the two contracts or obligations is the substitution of one of the parties. The new contract or obligation is on precisely the same terms as the original one, with the sole exception that one of the parties has changed.

OAS means Owner Activity Statement.

Offset drilling obligation is created when there is no well in a leased Crown spacing unit that laterally joins a spacing unit containing a producing freehold well. The well lessee has several options to provide compensation, one of which is Compensatory Royalty.

Offset notice (gas) is a notice given to the Crown lessee when a freehold spacing unit with a producing well laterally adjoins a Crown spacing unit with no producing well.

Old gas means natural gas other than new gas.

Old gas select price, in relation to a production month, means the amount per gigajoule prescribed pursuant to Section 6(3)(b) of the Regulation as the old gas select price for the year in which the production month occurs.

Old pentanes-plus means pentanes-plus other than new pentanes-plus.

OMAC adjustment means a deduction from the Gas Reference Price to reflect the deductibility of "Overhead, Marketing and Administration Costs" (OMAC). Inclusion of this deduction maintains the pricing consistency between the pre-1994 (field pricing) and post-1993 (downstream pricing) administrations. (Refer to Appendix D.)

Operator, with reference to a facility, means the person who is the operator of the facility according to the records of the Department.

Operating cost centre means an account in which the Department accumulates allowable operating costs for the purpose of calculating the Crown share of Operating Cost Allowances.

Out-of-service asset, in relation to Allowable Capital Cost, means an asset that is either shut in or abandoned.

Owner activity statement means a report referred to in section 21 of the Regulation.

Pentanes-plus means a mixture of hydrocarbons consisting wholly or mainly of pentanes and heavier hydrocarbons and obtained from natural gas by processing or otherwise, but does not include field condensate.

Pentanes par price is a factor used to calculate the pentanes-plus Crown royalty rate in the price sensitive royalty formula. It is the previous month Pentanes Reference Price reduced by an allowance for transportation.

Pentanes select price in relation to a production month, means the amount per cubic metre prescribed pursuant to Section 6(4)(a) of the Regulation as the select price for pentanes-plus for the year in which the production month occurs.

Pipeline fuel/loss allowance means the deduction from the Gas Reference price to recognize the cost of pipeline fuel/loss associated with natural gas.

Plant gate means

- in relation to a gas processing plant, the first point of measurement of the quantity of a gas product after it is obtained at that gas processing plant, or
- in relation to a reprocessing plant, the first point of measurement of the quantity of a gas product after it is obtained at that reprocessing plant.

Plant type facilities means EUB facilities that were operational at January 1, 1994, and which have an EUB-approved design capacity of 3,000 10^3m^3 per day or less and also facilities of any design capacity that became operational on or after January 1, 1994.

Point of delivery means the place where natural gas or a gas product is transferred from a gathering system or a gas processing plant into a transportation system (e.g. Nova).

Point of removal means, with respect to gas and gas products exported from Alberta, the place at which the gas or gas products exit from Alberta.

Pool means a natural underground reservoir containing or appearing to contain an accumulation of petroleum or natural gas separated or appearing to be separated from any other such accumulation.

Pre-1994 Regulation means the *Natural Gas Royalty* (Pre-1994) *Regulation* (Alta. Reg. 246/90).

Prepaid contract means a contract for the sale of gas where the seller receives payment for the gas in advance of the time at which the gas is to be delivered.

Pressure maintenance means an injection of gas, usually residue, into an oil reservoir for the purpose of maintaining the pressure in the reservoir to increase the oil recovered. May also be gas pressure maintenance (e.g. cycling scheme).

Pressure maintenance scheme means injection of gas into an EUB-approved scheme for the purposes of pressure maintenance.

PRIDE means Partner Regulatory Information Data Exchange.

Processed stream means a movement of product consisting of products recovered from a formation in either gaseous, liquid or solid form. A processed stream originates at the first point where the product stream is processed after the initial well head separation/measurement point.

Processing means the action of creating new product(s) from existing product(s) by:

- Extracting component gases and/or liquids from a product;
- Combining two or more products; and
- Altering the state in which a product exists, i.e. changing a product from a gaseous state to a liquid state.

Processing excludes the separation and/or recombination of product(s) which take place at a well site before they are transported to a processing plant.

Production means an unsold, unprocessed product stream, composed of products recovered from a formation in gaseous or liquid form, which originates at the first point of separation/measurement after the wellhead and ends at the next processing point.

Production entity means

- a drilling spacing unit prescribed by or established pursuant to regulations under the Oil and Gas Conservation Act to the extent that it is not included in an area described in the following subclauses:
  - the area of a project as defined in the Oil and Gas Conservation Act, or
  - a unit **area***.

Production month, in relation to any natural gas, gas product or field condensate, means the month in which it is recovered or obtained.

Propane, in addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane and butane.

Proprietary consumption means consumption by the person who is the owner of the commodity that is consumed.

Proprietary gas means gas that does not change ownership between a producing well and an injection well. For enhanced Oil Recovery Schemes, proprietary gas means indigenous production as defined in the 1994 Conventional Enhanced Oil Recovery Royalty Guidelines.

Provisional royalty is refundable royalty paid on differences between reports that should reconcile. It is refunded when reconciliation is made.

Provisional royalty assessment means an amount assessed by the Department to a Facility Operator on account of Provisional Royalty.

Proxy is a person who is authorized to represent and act on behalf of another person with respect to a particular function or purpose.

Purchased stream means a movement of product originating at the point where ownership changed from one business associate (legal entity) to another.

Quantities available for sale, in relation to a production month, means

- the quantities or volumes of gas products obtained during the production month at a gas processing plant or reprocessing plant, or
- the quantities or volumes of natural gas or gas products delivered from a gathering system during the production month, except quantities or volumes delivered to a gas processing plant, reprocessing plant or to a gathering system, or
- the quantities or volumes of natural gas or gas products disposed of during the production month before being delivered to a gas processing plant or reprocessing plant.

Rate adjustment, in relation to Unit Operating Cost Rates (UOCR), is part of the calculation to derive the UOCR for the current production year from the UOCR for the preceding production year.

Raw gas means gas that has not been processed.

Recognized aggregators means those companies considered as aggregators by the Resource Development Ministry for special purposes.

Reconciliation Facility Group means an operating cost centre that consists of a Department-approved grouping of EUB facilities that:

- reports volumes and costs at various facilities within the Reconciliation Facility Group;
- includes at least one facility that has an EUB-approved design capacity greater than 3,000 10^3m^3 per day; and
- includes all volumes and costs of the Reconciliation Facility Group.

Reference price means the price established by the Department for the Crown royalty share of gas, propane, butane and pentanes-plus, or any one of them. The price charged for the Crown royalty share may be reduced to reflect the condition of the product (raw, component of a mix), the location of the point at which royalty is triggered (transportation) or the requirement to store the product.

Regulation means the *Natural Gas Royalty Regulation, 1994* (Alberta Regulation 351/93).

Remaining useful life, in relation to a Facility Cost Centre, means the number of years of useful life initially approved by the Department for the facility reduced by one year for each year the facility is in service.

Reporting percent is the share of production from the well that is attributable to a royalty client. The sum of the reporting percentages for all royalty clients in a given well will equal 100%

Reprocessing plant means a plant that processes residue gas for the purpose of obtaining other gas products from the residue gas, but does not include a mainline straddle plant.

Reserve dedication means a contractual provision whereby specific gas reserves are committed to delivery under the contract.

Reservation charge means a specified, per unit cost based on total service entitlement, payable by a party contracting to use a transportation system's service.

Residue gas means the gaseous mixture consisting primarily of methane and obtained as a separate product at a gas processing plant or reprocessing plant.

Retired asset means an asset included in the Allowable Capital Cost of a Facility Cost Centre that has been permanently retired from service.

Royalty client means

- with reference to a Well/Well Group/Unit/Injection Scheme, a person shown in the records of the Department as a royalty client for that Well/Well Group/Unit/Injection Scheme, or
- with reference to the Crown's royalty share of excess or unallocated quantities of natural gas or gas products referred to in Section 22, a person who is deemed to be a royalty client in respect of those quantities by reason of the operation of Section 22(1)(c), (2)(c) or (3) of the Regulation, as the case may be.

Royalty compensation means money payable to the Crown under the Regulation as compensation in respect of the Crown's royalty share of natural gas or a gas product, the Crown's title to which is transferred pursuant to Section 14.

Royalty holiday well means a well event that is exempt from the payment of Crown royalty pursuant to the regulations.

Royalty network means a collection of interconnected processing and transportation (gathering) facilities that receive products either directly or indirectly from reservoirs where the Crown has an interest. The network is deemed to end when the product is delivered to:

- Commercial Transportation Facilities such as pipelines, railcars and trucks;
- Field Straddle Plants (except the case of unprocessed products);
- Mainline Straddle Plants; and
- Facilities for the purpose of injection.

Royalty paid bank means a quantity of gas or gas products that have been injected into an injection scheme, and on which the Crown royalty has been paid prior to January 1, 1994.

Royalty payer means a company or individual that pays royalty charges to the Department on natural gas and gas products.

Royalty responsibility reassignment means the assignment by one royalty client to one or more other royalty clients of all or a part of his responsibility for the Crown royalty share of quantities of gas and gas products allocated to him on an Owner Activity Statement.

Royalty trigger means an event reported on an Owner Activity Statement that will cause the Crown to calculate and invoice royalty on a quantity of gas or gas products.

S-CAP *means monthly/annual corporate average price for sulphur,* in relation to a royalty client, is the corporate average price for sulphur established for that royalty client for that month/year pursuant to Schedule 3, Section 3 of the Regulation.

S Reports are reports prepared by industry and submitted to EUB to report production, gathering, processing and injection volumes.

Select price (gas) – Two select prices, one for old vintage and another for new vintage gas, are determined annually by the Minister before the first production month in the calendar year. They are used in the formulas for calculating royalty rates for gas.

Select price (pentanes) is determined annually by the Minister before the first production month in the calendar year. It is used in the formula for calculating the royalty rate for pentanes.

Shrinkage is the gas equivalent volume of products extracted from gas.

Solution gas means the gaseous component of petroleum that is separated from crude oil after the recovery of petroleum from a well.

Special pentanes means a mixture of hydrocarbons consisting mainly of pentanes-plus and heavier hydrocarbons and obtained from natural gas by processing or otherwise, but does not include field condensate. This mixture is contaminated with sulphur or other compounds and must be stored, handled, and shipped separately from other pentanes-plus, and valued at a price consistently significantly lower than pentanes reference price.

Special pentanes processing allowance means the deduction from the Pentanes Reference Price to recognize the low value of specified pentanes streams received by the producers.

Specification product, in relation to natural gas liquids, means propane, butane or pentanes-plus that have been processed to a condition where they meet purchaser specifications for product quality.

Statement of account is the monthly statement from the Department to a royalty client describing the activity during a billing period in each of the royalty client's revenue accounts and the account balances at the close of the billing period.

Storage allowance means the deduction from the Propane Reference Price, the Butane Reference Price and the Pentanes Reference Price to recognize the cost of storage for transportation reasons associated with those products, excluding specification pentanes-plus.

Straddle plant means a gas processing facility constructed downstream from an existing field gas plant in order to increase the NGL/ethane recovery efficiency.

Stream ID means a Well or a Well Group or a Unit or an Injection Scheme.

Sulphur means a light yellow, non-metallic chemical element extracted from gas and sold as a by-product.

Sulphur Emission Control Assistance Program (SECAP) is a program that encourages and supports efficient recovery of sulphur from sour and acid gas as a means of environmental protection.

Swap means a transaction where the parties exchange a quantity of gas or a gas product at one location for a quantity of gas or a gas product at another location (*also see exchange*).

Terminated asset means an asset included in the Allowable Capital Cost of a Facility Cost Centre which has been terminated and will not be returned to service.

Transportation allowance means the deduction from the Propane Reference Price, the Butane Reference Price and the Pentanes Reference Price to recognize the cost of transportation associated with those products.

Transportation region, in relation to Transportation Allowances, means one of the four geographic transportation regions established for the purpose of calculating representative Transportation Allowances.

Trespass refers to a situation that occurs when a mineral is recovered from crown mineral rights without appropriate authorization.

Trespass damages means the value of the mineral recovered under a condition of trespass.

Undepreciated capital means the amount remaining after the depreciation is calculated and subtracted from the cost of the capital asset.

Unintentional trespass means trespass determined by the Crown to be unintentional.

Unique well identifier (UWI) is a 16-character code assigned by the EUB to a well to give it a unique numerical identity. The UWI, although based on the legal survey position of a well, is primarily for identification rather than location.

Unit is an agreement entered into by **lessees*** and **lessors*** of land (mineral rights) within a defined oil and/or gas pool whereby they agree to share both the costs of producing and the revenue obtained.

Unit area means the area of a unit operation.

Unit Operating Cost Rate (UOCR) means the dollar amount per unit of energy adjusted gas equivalent volume that the Department uses in calculating the monthly Crown share of Operating Cost Allowance of a royalty client.

Unprocessed stream means a movement of product consisting of products recovered from a formation in any form (gas, liquid or solid). An unprocessed stream originates at the first point of separation/measurement after the well head, and ends at the first processing point.

Unsold stream means a movement of product originating at a reservoir land moving through a network up to the point where ownership for the product changes hands. An unsold stream cannot have been previously sold.

Upstream facility means a facility that, in the sequence of flow from the wellhead to the point of final processing, is upstream from the facility at which the reference is made.

Valuation point adjustment (VPA) means a deduction in the Gas Reference Price to reflect the change in point at which gas pricing information is collected for gas sold to marketers. Inclusion of this deduction maintains the pricing consistency between the pre-1994 (field pricing) and post-1993 (downstream pricing) administrations. *(Refer to Appendix D.)*

Vintage refers to new gas, old gas, new pentanes-plus and old pentanes-plus that are separately defined.

Volumes sold means volumes sold as defined in the pre-1994 Regulation.

VPA means Valuation Point Adjustment.

W.I.O. means Working Interest Owner.

Well event means

- a part of a well completed in a zone and given a unique well identifier by the Board, or
- parts of a well completed in two or more zones and given a single unique well identifier by the Board, or
- a part of a well completed in a zone and recovering natural gas, but which has not yet been given a unique well identified by the Board, or
- parts of a well completed in and recovering natural gas from two or more zones during the period when the parts are considered by the Minister as a single well event for the purposes of the Regulation, and before the Board makes a decision whether or not to give the parts a single unique well identifier.

Well group means a well group referred to in Section 19 of the Regulation.

This Appendix features samples of:

Statement of Account O-2

Invoice O-3

Crown Royalty Detail Calculation O-4

Crown Royalty Detail Volumetric O-5

Owner Activity Statement (OAS) O-6

Low Productivity Calculation O-7

Alberta
RESOURCE DEVELOPMENT

Example 1: Depicting Level 1 Collection Notice
Assuming all of the opening balance relates to charges which were due on 1997/10/31.

STATEMENT OF ACCOUNT

ROYALTY PAYER INFORMATION	
CODE:	1234
NAME:	PARENT COMPANY
ADDRESS:	XXXXXXXXXXXXXXXXXXX CALGARY, AB CANADA X9X 9X9

REGULATORY AGENCY INFORMATION	
ISSUER:	DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE:	1997-11-10
STATEMENT NUMBER:	
ACCOUNT NUMBER:	G94XXXXXX

ROYALTY DEPOSIT ACCOUNT		
OPENING $	ADJUSTMENT $	CLOSING $
500,000.00	0.00	500,000.00

ACCOUNT SUMMARY		TOTAL $
OPENING BALANCE		250,000.00
PAYMENT APPLIED: 1997/10/29 TXN ID XXXXXXXX		(150,000.00)
CURRENT INVOICE CHARGES: 12345678901		346,449.00
PRIOR PERIOD CHARGES $: CPI COMMENCING 1997/11/01	62,949.00	
CURRENT PERIOD CHARGES $: CPI COMMENCING 1997/12/01	283,500.00	
PAYMENT APPLIED: 1997/11/07 TXN ID XXXXXXXX		(100,000.00)
CURRENT PERIOD INTEREST POSTED: 1997/11/07 TXN ID XXXXXXXX		179.69

PRINCIPAL $	FROM	TO	INTEREST RATE	INTEREST AMOUNT $
162,949.00	1997/112/01	1997/11/07	5.750%	179.69

	TOTAL $
CLOSING BLANCE	$346,628.69
CURRENT PERIOD INTEREST ACCRUED BUT UNPOSTED: TO 1997/11/10	29.75

PRINCIPAL $	FROM	TO	INTEREST RATE	INTEREST AMOUNT $	PER DIEM AMOUNT $
62,949.00	1997/11/08	1997/11/10	5.750%	29.75	9.92

	TOTAL $
AMOUNT PAYABLE: AS OF 1997/11/10	$346,658.44

COLLECTION NOTICE: PLEASE NOTE YOUR CLOSING BALANCE INCLUDES CHARGES PAST DUE WHICH ARE ACCRUING ADDITIONAL INTEREST UNTIL PAYMENT IS RECEIVED

MESSAGE(S): RE: ALBERTA ROYALTY TAX CREDIT: SEE THE ARTICLE IN OUR JULY '97 INFORMATION BULLETIN ABOUT NEW REPORTING REQUIREMENTS FROM ALBERTA TREASURY WITH RESPECT TO THE ALBERTA TAX CREDIT AND ROYALTY CREDIT FOR INDIVIDUALS AND TRUSTS PROGRAMS, RELATED TO GAS ROYALTY ADJUSTMENTS FOR 1994 TO 1996.

CC: ALBERTA TREASURY, TAX AND REVENUE ADMINISTRATION

Reference Number: 12345678

Page 1

Alberta
RESOURCE DEVELOPMENT

INVOICE

ROYALTY PAYER INFORMATION

CODE: 1234
NAME: PARENT COMPANY
ADDRESS: XXXXXXXXXXXXXXXXXX
CALGARY, AB
CANADA
X9X 9X9

REGULATORY AGENCY INFORMATION

ISSUER: DEPARTMENT OF RESOURCE DEVELOPMENT
ISSUE DATE: 1997-10-31
INVOICE DUE DATE: 1997-11-30
BILLING PERIOD: 1997-08
INVOICE NUMBER: 12345678901
ACCOUNT NUMBER: G94XXXXXX

		Prior Period $	Current Period $	Total $
Charges:	Crown Royalty	59,000.00	250,000.00	309,000.00
	Enhanced Oil Recovery Operating cost Adjustment	10,000.00	50,000.00	60,000.00
	Provisional Royalty Assessment	10,000.00	25,000.00	35,000.00
	Penalties		5,000.00	5,000.00
	Total Charges	79,000.00	330,000.00	409,000.00
Credits	Monthly Proprietary Waiver	(15,000.00)		(15,000.00
	Monthly Capital Cost Deduction		(15,000.00)	(15,000.00)
	Monthly Custom Processing Fee Deduction		(5,000.00)	(5,000.00)
	Injection Credits		(25,000.00)	(25,000.00)
	Total Credits	(15,000.00)	(45,000.00)	(60,000.00)
Adjustments	Annual Capital Cost Adjustment	(5,000.00)		(5,000.00)
	Annual Custom Processing Fee Adjustment	(1,000.00)		(1,000.00)
	Other Financial Transactions		(1,500.00)	(1,500.00)
	Interest: Prior Period	4,949.00		4,949.00
	Total Adjustments	(1,051.00)	(1,500.00)	(2,551.00)
TOTAL:		$62,949.00	$283,500.00	$346,449.00

Terms and Conditions: The 'Prior Period Total' is now due and includes prior period interest to the invoice issue date and will continue to accrue current period interest commencing the first day after the invoice ISSUE date until payment is received. The 'Current Period Total' is due on the Invoice Due Date and will incur current period interest commencing the first day after the invoice DUE date.
The Department will charge interest on underpayments or late payments of invoiced amounts commencing the first day after the due date and continuing until the date the payment is received. Interest will be calculated at the Alberta Treasury Branch prime lending rate plus 1%. Interest will not be paid on overpayments of invoiced amounts.

Cheques Payable To: Provincial Treasurer of Alberta Resource Development

Reference Number: 1234567

Page 1

CROWN ROYALTY DETAIL CALCULATION

Issue Date: 1994-04-01
Royalty Client: 1234
Name: Parent Company
Facility: AB-GP-1003
Production Period: 1994-01

Invoice #: 12345678901

Royalty Payer Code: 1234
Name: Parent Company
Address: XXXXXXXXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Royalty Product	Reference Price $	Price Adjustment	Raw Gas Factor	Corporate Gas Factor	Transportation Rate	Storage Rate $	Fractionation Rate $	Conversion Factor	Unit Operating Cost Rate $
GAS	1.93							1.00000	6.00
C2-MX	1.93							0.28132	6.00
C3-MX	74.47				6.35	0.98	8.00	0.65554	6.00
C4-MX	67.24				6.35	0.98	8.00	0.72793	6.00
C5-MX	112.37				6.35	0.98	8.00	0.78783	6.00
SUL								0.73785	6.00

Royalty Product	Client Volumetric Totals		Crown Interest %	Vintage		Crown Royalty Rate	Crown Royalty		Gross Royalty $	Royalty Exemption $	Operating Deduction $	Charge Total $	Interest Charge $
	Quantity	Heat		Type	%		Quantity	Heat					
	Charge Type: CROWN ROYALTY					Stream ID: AB-IS-98765							
GAS	2000.0	82000	100.0000000%	OLD	100.00%	35.00000%	700.00	28700.00	55,391.00		4,200.00	51,191.00	
C2-MX	1500.0	27878	100.0000000%	OLD	100.00%	35.00000%	525.00	9757.34	18,831.66		886.16	17.945.50	
C3-MX	1250.0		100.0000000%			30.00000%	375.00		22,177.50		1,474.97	20,702.53	
C4-MX	1000.0		100.0000000%			30.00000%	300.00		15,573.00		1,310.27	14,262.73	
C5-MX	850.0		100.0000000%	OLD	100.00%	39.08061%	332.19		32,235.25		1,570.23	30,665.02	

FACILITY: AB-GP-1003	
CHARGE TYPE: CROWN ROYALTY	$134,766.78
INTEREST CHARGE:	$0.00
	$134,766.78

ROYALTY CLIENT SUMMARY:	
CHARGE TYPE: CROWN ROYALTY	$163,016.83
INTEREST CHARGE:	$0.00
	$163,016.83

ROYALTY PAYER SUMMARY:	
CHARGE TYPE: CROWN ROYALTY	$341,373.26
INTEREST CHARGE:	$0.00
	$341,373.26

CROWN ROYALTY DETAIL VOLUMETRIC

Issue Date: 1994-04-01
Royalty Client: 1234
Name: Parent Company
Facility: AB-GP-1003
Production Period: 1994-01

Invoice #: 12345678901

Royalty Payer Code: 1234
Name: Parent Company
Address: XXXXXXXXXXXXXXXXXXXXXXX
Calgary, AB
X9X 9X9

Royalty Product	Source Document	Source Document Details Facility	Operator	Owner	Filing Date	Activity	Product	Quantity	Heat	Allocator %	Client Volumetric Total Quantity	Heat
	Charge Type: CROWN ROYALTY				Stream ID: AB-IS-98765							
GAS	OAS	AB-GP-1003	1234	1234	1994-03-15	PROC	GAS	2000.0	82000		2000.0 2000.0	82000 82000
C2-MX	OAS	AB-GP-1003	1234	1234	1994-03-15	PROC	C2-MX	1500.0			1500.0 1500.0	
C3-MX	OAS	AB-GP-1003	1234	1234	1994-03-15	PROC	C3-MX	1250.0			1250.0 1250.0	
C4-MX	OAS	AB-GP-1003	1234	1234	1994-03-15	PROC	C4-MX	1000.0			1000.0 1000.0	
C5-MX	OAS	AB-GP-1003	1234	1234	1994-03-15	PROC	C5-MX	850.0			850.0 850.0	

OWNER ACTIVITY STATEMENT

				Name
Province	Prov.	Type	Code	Alberta
Facility	AB	IF	9000	Parent's Injection Facility
Operator			1234	Parent Company
Owner			1234	Parent Company
Allocator				

Production Period	1994-01
Filing Date	1994-03-15
Operator Contact Person	Bernie
Operator Phone Number	(403) 260-1000
Operator Fax Number	(403) 260-0000
Owner Contact Person	Bernie
Owner Fax Number	(403) 260-0000

Stream I.D.		Stream	Location						Quantity		Heat Content		Destination I.D.		
Prov.	Type	Code	Category	Prov.	Type	Code	Product	Activity	Gross	Net	Gross	Net	Prov.	Type	Code
AB	IS	98765	INJECTION	AB	GP	1003	GAS	TSF	4000.0	2000.0	164000	82000	AB	IF	9000
AB	IS	98765	INJECTION	AB	GP	1003	C4-MX	TSF	1000.0	500.0			AB	IF	9000
AB	IS	98765	INJECTION	AB	GP	1003	C5-MX	TSF	850.0	425.0			AB	IF	9000
AB	IS	98765	INJECTION	AB	IF	9000	GAS	FUEL	100.0	50.0	4100	2050			
AB	IS	98765	INJECTION	AB	IF	9000	C4-MX	FUEL	50.0	25.0					
AB	IS	98765	INJECTION	AB	IF	9000	C5-MX	FUEL	30.0	15.0					
AB	IS	98765	INJECTION	AB	IF	9000	GAS	INJ	3900.0	1950.0	159900	79950			
AB	IS	98765	INJECTION	AB	IF	9000	C4-MX	INJ	950.0	475.0					
AB	IS	98765	INJECTION	AB	IF	9000	C5-MX	INJ	820.0	410.0					

LOW PRODUCTIVITY CALCULATION

Invoice #: 12345678901

Issue Date: 1994-04-01
Royalty Client: 1234
Name: Parent Company
Facility: AB-GP-1000
Production Period: 1994-01

Royalty Payer Code: 1234
Name: Parent Company
Address: XXXXXXXXXXXX
Calgary, AB
X9X 9X9

Stream Type: WG
Stream ID: 004219
Gas Vintage Type: NEW
Gas Vintage Percentage: 44.03
Production Period: 1994-01

Well ID	Production	Hours	Daily Average	Allocation %	Allocated Production	OLD Low Productivity		NEW Low Productivity	
						Royalty Factor	Adjustment	Royalty Factor	Adjustment
100888999777W400	28.2	67	10.1	100.00000%	28.2	4.85484%	0.76627	3.45652%	0.97474
100888999777W402	162.4	690	5.6	100.00000%	162.4	13.29700%	12.08634	9.46712%	15.37460
100222654321W402	301.6	737	9.8	100.00000%	301.6	5.26305%	8.884.33	3.74716%	11.30143
Sub-total	492.2				492.2		21.73694		27.65077
Other Well Production	257.8				257.8		0.00000		0.00000
Total Production	750.0				750.0		21.73694		27.65077
				Low Productivity Adjustment:			6.58503%		

NOTE: Production obtained from AEUB S1 data.

The forms contained within this Appendix are for the use of Royalty Clients to submit to the Department. These are base copies from which additional copies can be made and used.

The forms are:

FORM	
595	Sulphur Emission Control Assistance Program (SECAP) Schedule 1
AC1	Allowable Costs Facility Cost Centre Setup/Change
AC2-V1	Allowable Costs Capital Cost Allowance Production Years 1994, 1995 and 1996
AC2-V2	Allowable Costs Capital Cost Allowance Production Years 1997 and Onwards
AC3	Capital Costs Allowance Reallocations
AC4	Allowable Costs Operating Costs
AC5-V1	Allowable Costs Custom Processing Fees Paid Production Years 1994, 1995 and 1996
AC5-V2	Allowable Costs Custom Processing Fees Paid Production Years 1997 and Onwards.
AC10	Application For Plant Type Code and Transportation Region Code
CPAF	Custom Processing Adjustment Factor
GR1	Application to Grandfather Co-Generation or Long-term Contracts
GR2	Annual Statement of Grandfathered Contact Sales
ICC1	Invoice Consolidation Concurrence
NGL1	NGL Valuation and Transportation
NGL2	Storage Costs (For Production Year 1994 Only)
OAS	Owner Activity Statement
OC1	Facility Operator Change Form
PW1	Monthly Statement of Proprietary Gas - Royalty Waived
RMF1	Consolidated Single Well Group Setup/Change
RMF2	Reassignment of Volumes Setup/Change
RMF3	Single Well/Injection Scheme Setup/Change
VA1	Election for Gas Valuation
VA2	Corporate Average Price Calculation Gas
VA3	Annual Corporate Average Price Calculation - Sulphur
VA4	Monthly Corporate Average Price Calculation - Sulphur
	Request for Refund
	Vendor Maintenance Request Form
OFSG	Otherwise Flared Solution Gas Royalty Waiver Program Application Form
	Gas Royalty Registry Update

Alberta
RESOURCE DEVELOPMENT

SULPHUR EMISSION CONTROL ASSISTANCE PROGRAM (SECAP) SCHEDULE 1

595

PART 1: FACILITY IDENTIFICATION

1.1 ______________________ PLANT NAME

1.2 ______________________ EUB FACILITY CODE

1.3 ______________________ PLANT OPERATOR

1.4 ______________________ EUB APPROVAL NO.

1.5 ______________________ EUB APPROVAL DATE

PART 2: ELIGIBLE CAPITAL COSTS ______________ YEAR INCURRED IN

(Attach invoices for items over $1,000.00)

2.1 APPROVED EQUIPMENT	2.2 COSTS
2.3 TOTAL ELIGIBLE CAPITAL COSTS	

PART 3: ELIGIBLE OPERATING EXPENSES ______________ YEAR INCURRED IN

(Attach invoices for items over $1,000.00)

3.1 LABOUR	
3.2 MATERIALS	
3.3 PARTS/SUPPLIES	
3.4 TOTAL ELIGIBLE OPERATING EXPENSES	

PART 4: CALCULATION OF CREDIT

CAPITAL COST CREDIT = ______________ 4.1 ELIGIBLE CAPITAL COSTS X [illegible] = ______________ 4.2 CAPITAL COST CREDIT

OPERATING EXPENSE CREDIT = ______________ 4.3 ELIGIBLE OPERATING EXPENSES X [illegible] = ______________ 4.4 OPERATING EXPENSE CREDIT

TOTAL CREDIT ______________ 4.5 TOTAL

4.6 NAME OF PARTICIPANT	4.7 ROYALTY CLIENT ID	4.8 PERCENTAGE OF CREDIT	4.9 CREDIT
	TOTAL	100%	

PART 5: CERTIFICATION

5.1 I, ______________________ HEREBY

- THAT THE STATEMENTS AND INFORMATION CONTAINED IN THIS APPLICATION ARE TRUE AND CORRECT
- THAT ALL THE PARTICIPANTS ON WHOSE BEHALF COSTS HAVE BEEN INCURRED AGREE TO THE ALLOCATION OF BENEFITS AS SET OUT ABOVE
- THAT CAPITAL COSTS AND/OR OPERATING EXPENSES HAVE NOT BEEN CLAIMED UNDER GAS COST ALLOWANCE (GCA)
- THAT COSTS CLAIMED IN THIS APPLICATION DO NOT INCLUDE PROFITS RESULTING FROM TRANSACTIONS BETWEEN CONNECTED PARTIES

5.2 DATED THIS __________ DAY OF ______________ , 19 ____

5.4 ______________________ NAME OF AUTHORIZED COMPANY OFFICIAL (please print)

5.3 ______________________ SIGNATURE OF AUTHORIZED COMPANY OFFICIAL

5.5 ______________________ TITLE

[illegible]

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
FACILITY COST CENTRE
SETUP/CHANGE
AC1

PART 1: FACILITY COST CENTRE OPERATOR DETAIL

1.1 CHECK ONE: ☐ SETUP ☐ CHANGE

1.2 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.3 REASON FOR CHANGE ____________________

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ____________________ FACILITY COST CENTRE OPERATOR NAME

1.6 ____________________ CONTACT PERSON

1.7 (   ) ____________________ TELEPHONE

PART 2: FACILITY COST CENTRE

2.5 ☐ REMAINING USEFUL LIFE (YRS)

2.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

2.2 ____________________ DESCRIPTION OF EUB FACILITY

2.3 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

2.4 ____________________ DESCRIPTION OF FACILITY COST CENTRE

2.6 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO

2.7 TERMINATION DATE ☐☐☐☐☐☐ YR. MO

2.8 ASSOCIATED EUB FACILITY CODE ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

2.9 PREVIOUS FACILITY COST CENTRE CODE ☐☐☐☐☐☐☐☐–☐

☐☐☐☐☐☐☐☐–☐ ☐☐☐☐☐☐☐☐–☐

☐☐☐☐☐☐☐☐–☐ ☐☐☐☐☐☐☐☐–☐

2.10 REPORTED EUB FACILITY CODE ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

PART 3: CHANGE IN FACILITY COST CENTRE OPERATOR

3.3 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO.

3.1 ☐☐☐☐☐☐☐ NEW FACILITY COST CENTRE OPERATOR ID

3.2 ____________________ NEW FACILITY COST CENTRE OPERATOR NAME

PART 4: FACILITY COST CENTRE OWNERSHIP

4.1 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO.

4.2 CLIENT ID	4.3 FACILITY COST CENTRE OWNER NAME	4.4 % OWNERSHIP	
		100	00000%

PART 5: FACILITY COST CENTRE TYPE

5.1 COMPRESSING ☐ GATHERING ☐ PROCESSING ☐ 5.2 ____________________ PROCESSING SUBTYPE

PART 6: SHUT IN/REACTIVATION

6.1 SHUT IN ☐ 6.2 EFFECTIVE YEAR ☐☐☐☐

[illegible]

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
FACILITY COST CENTRE
SETUP/CHANGE
AC1 (PART 4 CONTINUATION)

PART 1: FACILITY COST CENTRE OPERATOR

1.2 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ______________________ FACILITY COST CENTRE OPERATOR NAME

1.6 ______________________ CONTACT PERSON

1.7 (___) ______________ TELEPHONE

PART 2: FACILITY COST CENTRE

2.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

2.2 ______________________ DESCRIPTION OF EUB FACILITY

2.3 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

2.4 ______________________ DESCRIPTION OF FACILITY COST

PART 4: FACILITY COST CENTRE OWNERSHIP CONTINUED

4.2 CLIENT ID	4.3 FACILITY COST CENTRE OWNER NAME	4.4 % OWNERSHIP	

PAGE ______ of ______

[illegible]

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V1
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR

1.5 ________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.8 ________________ CONTACT PERSON

1.9 (____) ________________ TELEPHONE

PART 2: CAPITAL COST ALLOWANCE CALCULATION

		ALLOWABLE CAPITAL COSTS ($)
2.1	CUMULATIVE ALLOWABLE CAPITAL JAN 1 OR ______	
2.2	ALLOWABLE CAPITAL COST JAN 1 OR ______	
2.3	CAPITAL ADDITIONS (CARRIED FROM PART 3)	
2.4	CUMULATIVE ALLOWABLE CAPITAL DEC 31 OR ______	
2.5	ALLOWABLE CAPITAL COST BEFORE DEPRECIATION DEC 31 OR ______	
2.6	DEPRECIATION ______ / 12	
2.7	ALLOWABLE CAPITAL COST AFTER DEPRECIATION DEC 31 OR ______	

		RETURN ON AVERAGE CAPITAL ($)
2.8	AVERAGE CAPITAL	
2.9	LAND	
2.10	AVERAGE SPARE PARTS INVENTORY	
2.11	TOTAL	

		CAPITAL COST ALLOWANCE ($)
2.12	RETIREMENTS	
2.13	DEPRECIATION	
2.14	RETURN ON AVERAGE CAPITAL ______ / 12	
2.15	CAPITAL COST ALLOWANCE	

2.16 ☐ REMAINING USEFUL LIFE (YRS.)

PART 3: CAPITAL ADDITIONS

3.1 ADDITIONS / DISPOSITIONS / RETIREMENTS (Please provide description)	3.2 TYPE	3.3 AMOUNT ($)
	3.4 TOTAL	

PART 4: CAPITAL COST ALLOCATION ALLOCATIONS

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 CAPITAL COST ALLOWANCE DISTRIBUTIONS%	
	4.4 FACILITY CUSTOM PROCESSING ADJUSTMENT FACTOR		
	4.5 TOTAL CAPITAL COST ALLOWANCE ALLOCATED	100	00000%

99/01/9

Alberta
RESOURCES DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V1 (PART 3 CONTINUATION)
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ______________________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ______________________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.8 ______________________________ CONTACT PERSON

1.9 ( ) ______________________________ TELEPHONE

PART 3: CAPITAL ADDITIONS CONTINUED

3.1 ADDITIONS / DISPOSITIONS / RETIREMENTS (Please provide description)	3.2 TYPE	3.3 AMOUNT ($)

PAGE ______ of ______

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Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V1 (PART 4 CONTINUATION)
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 ☐☐ ☐☐ ☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐ - ☐ FACILITY COST CENTRE CODE

1.3 ____________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ____________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐ ☐☐ ☐☐ YR. MO. DY.

1.8 ____________________ CONTACT PERSON

1.9 (___) ____________________ TELEPHONE

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS CONTINUED

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 CAPITAL COST ALLOWANCE DISTRIBUTIONS%	

PAGE ______ of ______

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V2
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 ☐☐|☐☐|☐☐☐☐☐☐☐ PROV. FAC. TYPE SUB FACILITY CODE
1.2 ☐☐☐☐☐☐☐☐☐☐☐-☐ FACILITY COST CENTRE CODE

1.3 ____________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID
1.5 ____________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐
1.7 DATE PREPARED ☐☐☐☐|☐☐|☐☐ YR. MO. DY.

1.8 ____________________ CONTACT PERSON
1.9 (   ) ____________________ TELEPHONE

PART 2: CAPITAL COST ALLOWANCE CALCULATION

		ALLOWABLE CAPITAL COSTS ($)
2.1	CUMULATIVE ALLOWABLE CAPITAL JAN 1 OR ______	
2.2	ALLOWABLE CAPITAL COST JAN 1 OR ______	
2.3	CAPITAL ADDITIONS (CARRIED FROM PART 3)	
2.4	CUMULATIVE ALLOWABLE CAPITAL DEC 31 OR ______	
2.5	ALLOWABLE CAPITAL COST BEFORE DEPRECIATION DEC 31 OR ______	
2.6	DEPRECIATION ______ / 12	
2.7	ALLOWABLE CAPITAL COST AFTER DEPRECIATION DEC 31 OR ______	

2.16 ☐ REMAINING USEFUL LIFE (YRS.)

		RETURN ON AVERAGE CAPITAL ($)
2.8	AVERAGE CAPITAL	
2.9	LAND	
2.10	AVERAGE SPARE PARTS INVENTORY	
2.11	TOTAL	

		CAPITAL COST ALLOWANCE ($)
2.12	RETIREMENTS	
2.13	DEPRECIATION	
2.14	RETURN ON AVERAGE CAPITAL ______ / 12	
2.15	CAPITAL COST ALLOWANCE	

PART 3: CAPITAL ADDITIONS

3.1 ADDITIONS / DISPOSITIONS / RETIREMENTS (Please provide description)	3.2 TYPE	3.3 AMOUNT ($)
	3.4 TOTAL	

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 CAPITAL COST ALLOWANCE DISTRIBUTIONS%	
	4.4 CUSTOM PROCESSING ADJUSTMENT FACTOR %		
	4.5 TOTAL CAPITAL COST ALLOWANCE ALLOCATED	100	00000%

PAGE 1 of ______

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Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V2
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 PROV. FAC. TYPE EUB FACILITY CODE

1.2 FACILITY COST CENTRE CODE -

1.3 DESCRIPTION OF FACILITY COST CENTRE

1.4 FACILITY COST CENTRE OPERATOR ID

1.5 FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR

1.7 DATE PREPARED YR. MO. DY.

1.8 CONTACT PERSON

1.9 ( ) TELEPHONE

PART 5: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

5.3 UNIT 10^3m^3 ☐ m^3 ☐ t ☐

5.1 CLIENT ID	5.2 CLIENT NAME	5.4 CUSTOM VOLUMES

5.5 TOTAL CUSTOM VOLUMES

5.6 TOTAL FACILITY COST CENTRE THROUGHPUT

5.7 CUSTOM PROCESSING ADJUSTMENT FACTOR %

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V2 (PART 3 CONTINUATION)
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 ☐☐ | ☐☐ | ☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐ – ☐ FACILITY COST CENTRE CODE

1.3 ______________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ______________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐ | ☐☐ | ☐☐ YR. MO. DY.

1.8 ______________________ CONTACT PERSON

1.9 (   ) ______________________ TELEPHONE

PART 3: CAPITAL ADDITIONS CONTINUED

3.1 ADDITIONS / DISPOSITIONS / RETIREMENTS (Please provide description)	3.2 TYPE	3.3 AMOUNT ($)

PAGE ______ of ______

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Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CAPITAL COST ALLOWANCE
AC2-V2 (PART 4 CONTINUATION)
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ____________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ____________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1. ____________________ CONTACT PERSON

1. (   ) ____________________ TELEPHONE

PART 4: CAPITAL COST ALLOWANCE ALLOCATIONS CONTINUED

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 CAPITAL COST ALLOWANCE DISTRIBUTIONS%	

PAGE ______ of ______

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Alberta
RESOURCE DEVELOPMENT

CAPITAL COSTS ALLOWANCE REALLOCATIONS
AC3

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ______________________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ CLIENT ID

1.5 ______________________________ CLIENT NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.8 ______________________________ CONTACT PERSON

1.9 (____) ______________________ TELEPHONE

PART 2: CAPITAL COST ALLOWANCE REALLOCATIONS

2.1 CLIENT ID	2.2 CLIENT NAME	2.3 PERCENTAGE OF ORIGINAL ALLOCATION	

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
OPERATING COSTS
AC4

PART 1: IDENTIFICATION

1.1 ☐☐|☐☐|☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ____________________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ____________________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐|☐☐|☐☐ YR MO. DY.

1.8 ____________________ CONTACT PERSON

1.9 (___)____________ TELEPHONE

PART 2:

2.1 ALLOWABLE OPERATING COSTS ($)

1	LABOUR		7	MAINTENANCE	
2	MATERIALS		8	AUTOMOTIVE	
3	CHEMICALS		9	INSURANCE	
4	TRANSPORTATION		10	PROPERTY TAXES	
5	CONTRACT SERVICES		11	SURFACE RENTALS	
6	UTILITIES				

2.2 OTHER ALLOWABLES (DESCRIPTION)	2.3 OTHER ALLOWABLES (ACTUAL OPERATING COSTS) ($)

2.4 DIRECT ALLOWABLE OPERATING COSTS
2.5 OVERHEAD __________ %
2.6 DIRECT ALLOWABLE OPERATING COSTS & OVERHEAD
2.7 WORKING CAPITAL ALLOWANCE
2.8 TOTAL ALLOWABLE OPERATING COSTS

[illegible]

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V1
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 CLIENT ID

1.2 CLIENT NAME

1.3 PRODUCTION YEAR

1.4 DATE PREPARED YR. MO. DY.

1.5 CONTACT PERSON

1.6 TELEPHONE ( )

PART 2: CUSTOM PROCESSING FEES PAID WILL BE ADJUSTED BY THE UNIT OPERATING COST RATE APPLIED AT THE EUB FACILITY

2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE	2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE

OFFICIAL DECLARATION: I HEREBY DECLARE THAT I HAVE NO OWNERSHIP IN ANY OF THE FACILITY COST CENTERS (GCA FACILITIES) FOR WHICH A CUSTOM PROCESSING FEE HAS BEEN CLAIMED.

2.3 AUTHORIZED SIGNATURE

2.5 TITLE OF CORPORATE SIGNING OFFICER

2.4 NAME OF CORPORATE SIGNING OFFICER

2.6 DATE

PART 3: CUSTOM PROCESSING FEES PAID WILL BE ADJUSTED BY THE DELAYER COMPONENT OF THE UNIT OPERATING COST RATE IDENTIFIED

3.1 EUB FACILITY PROV./FAC. TYPE/CODE	3.2 CUSTOM PROCESSING FEE PAID ($)	PRODUCTS/VOLUMES DERIVED		3.5 CUSTOM SERVICES PAID		
		3.3 PRODUCT CODE	3.4 VOLUME	COMPRESSING	GATHERING	PROCESSING

OFFICIAL DECLARATION: I HEREBY DECLARE THAT THE CUSTOM SERVICE OBTAINED APPLIES TO THE DELAYERED COMPONENT(S) IDENTIFIED

3.6 AUTHORIZED SIGNATURE

3.8 TITLE OF CORPORATE SIGNING OFFICER

3.7 NAME OF CORPORATE SIGNING OFFICER

3.9 DATE

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V1 (PART 2 CONTINUATION)
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ____________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐|☐☐|☐☐ YR. MO. DY.

1.5 ____________________ CONTACT PERSON

1.6 (___)__________ TELEPHONE

PART 2: CUSTOM PROCESSING FEES PAID WILL BE ADJUSTED BY THE UNIT OPERATING COST RATE APPLIED AT THE EUB FACILITY CONTINUED

2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE	2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE

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Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V1 (PART 3 CONTINUATION)
PRODUCTION YEARS 1994, 1995 AND 1996

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐ CLIENT ID

1.2 ________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ________________ CONTACT PERSON

1.6 ( ) ________________ TELEPHONE

PART 3: CUSTOM PROCESSING FEES PAID WILL BE ADJUSTED BY THE DELAYER COMPONENT OF THE UNIT OPERATING COST RATE IDENTIFIED CONTINUED

3.1 EUB FACILITY PROV./FAC. TYPE/CODE	3.2 CUSTOM PROCESSING FEE PAID ($)	PRODUCTS/VOLUMES DERIVED		3.5 CUSTOM SERVICES PAID		
		3.3 PRODUCT CODE	3.4 VOLUME	COMPRESSING	GATHERING	PROCESSING

PAGE ______ of ______

[illegible]

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V2
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ______________________ CONTACT PERSON

1.6 (   ) ______________________ TELEPHONE

PART 2: NON OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE	2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE

OFFICIAL DECLARATION: I HEREBY DECLARE THAT I HAVE NO OWNERSHIP IN ANY OF THE FACILITY COST CENTRES FOR WHICH A CUSTOM PROCESSING FEE HAS BEEN CLAIMED.

2.3 ______________________ AUTHORIZED SIGNATURE

2.5 ______________________ TITLE OF CORPORATE SIGNING OFFICER

2.4 ______________________ NAME OF CORPORATE SIGNING OFFICER

2.6 ______________________ DATE

PART 3: OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

3.1 EUB FACILITY PROV./FAC. TYPE/CODE	3.2 CUSTOM PROCESSING FEE PAID ($)	3.3 ENERGY-ADJUSTED GAS EQUIVALENT VOLUME	3.4 EXCESS CAPACITY	3.5 CUSTOM SERVICES PAID		
				COMPRESSING	GATHERING	PROCESSING

OFFICIAL DECLARATION: I HEREBY DECLARE THAT THE CUSTOM SERVICE OBTAINED APPLIES TO THE DELAYERED COMPONENT(S) IDENTIFIED OR IS EXCESS CAPACITY.

3.6 ______________________ AUTHORIZED SIGNATURE

3.8 ______________________ TITLE OF CORPORATE SIGNING OFFICER

3.7 ______________________ NAME OF CORPORATE SIGNING OFFICER

3.9 ______________________ DATE

99/01/9

Alberta
RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V2 (PART 2 CONTINUATION)
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ______________________ CONTACT PERSON

1.6 (   ) ______________________ TELEPHONE

PART 2: NON OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY

2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE	2.1 CUSTOM PROCESSING FEE PAID ($)	2.2 EUB FACILITY PROV./FAC. TYPE/CODE

PAGE ______ of ______

98/01/9

RESOURCE DEVELOPMENT

ALLOWABLE COSTS
CUSTOM PROCESSING FEES PAID
AC5-V2 (PART 3 CONTINUATION)
PRODUCTION YEARS 1997 AND ONWARDS

PART 1: **IDENTIFICATION**

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐ ☐☐ ☐☐ YR. MO. DY.

1.5 ______________________ CONTACT PERSON

1.6 (   ) ______________________ TELEPHONE

PART 3: **OWNER IN FACILITY COST CENTRE(S) TIED TO EUB FACILITY**

3.1 EUB FACILITY PROV./FAC. TYPE/CODE	3.2 CUSTOM PROCESSING FEE PAID ($)	3.3 ENERGY-ADJUSTED GAS EQUIVALENT VOLUME	3.4 EXCESS CAPACITY	3.5 CUSTOM SERVICES PAID		
				COMPRESSING	GATHERING	PROCESSING

PAGE ______ **of** ______

99/01/9

Alberta
RESOURCE DEVELOPMENT

APPLICATION FOR PLANT TYPE CODE AND TRANSPORTATION REGION CODE
AC10

Please complete Part A and mail/fax to Department of Resource Development, Attn: Deen Khan, Fax # (780) 422-8732

PART A:

This application is for a (please circle): **New** Plant Type Code

Amended Plant Type Code

EUB Facility Code ____________________

EUB Approval Number ____________________

Date of Approval ____________________

Facility Location (LSD) ____________________

Facility Name ____________________

Facility Start-up (Operation) Date ____________________

Facility Operator Name ____________________

Facility Operator ID ____________________

Contact Name ____________________

Contact Phone No. ____________________

Contact Fax No. ____________________

Please answer the following questions by circling "Yes" or " No".

1. Is this a Gas Gathering System?

Yes? **Do not answer questions 2 to 4**
No? **Answer questions 2 to 4**

2. Can this Plant handle any (>0m^3) hydrocarbon liquid production (NGL, C3, C4, or C5+)?

Yes? **Wet**
No? **Dry**

3. (a) Can this Plant remove acid gas?

Yes? **Proceed to question 3b**
No? **Proceed to question 4**

(b) Does this Plant recover sulphur?

Yes?
No?

4. **Does this Plant have any sulphur emissions outside of those coming from a non-regenerative sweetening unit or mole sieve?**

(Refer to page 382 of the Principles and Procedures)

Yes?	**Sour**
No?	**Sweet**

Signing Officer ____________________ Date ____________________

Part B: FOR DEPARTMENT OF RESOURCE DEVELOPMENT USE ONLY

Plant Type Code Assigned

1	**Gathering System or Dry & Sweet**
2	**Wet & Sweet**
3	**Dry & Sour**
4	**Wet & Sour**
5	**Wet or Dry & Sour & Sulphur Produced**

Date Application Received ____________________

Plant Type Effective Date ____________________

Transportation Region Code ____________________

Signing Officer ____________________ Date ____________________

Note:

1. **Application must be received by the Department on or before the 15th day of the month following the facility's start up date.**
2. **The Plant Type Effective Date for a new facility, for UOCR purposes, is the first day of the month in which the facility started operations.**
3. **After 1994, the effective date of a change is January of a year, if the plant construction/re-engineering has been approved by the EUB, and operation commences on or before March 31 of the same year or January 1 of the following year if operation commences after March 31.**
4. **If you have any questions, please cal Deen Khan at (780) 422-9247.**
5. **A copy of the completed AC10 form will be mailed/faxed back to the client.**

Alberta
RESOURCE DEVELOPMENT

CUSTOM PROCESSING ADJUSTMENT FACTOR (CPAF)

PART 1: IDENTIFICATION

1.1 ☐☐☐☐☐☐☐☐☐☐☐ PROV. FAC. TYPE EUB FACILITY CODE

1.2 ☐☐☐☐☐☐☐☐–☐ FACILITY COST CENTRE CODE

1.3 ______________ DESCRIPTION OF FACILITY COST CENTRE

1.4 ☐☐☐☐☐☐☐ FACILITY COST CENTRE OPERATOR ID

1.5 ______________ FACILITY COST CENTRE OPERATOR NAME

1.6 PRODUCTION YEAR ☐☐☐☐

1.7 DATE PREPARED ☐☐☐☐☐☐☐☐ YR MO. DY.

1.8 ______________ CONTACT PERSON

1.9 (___) ______________ TELEPHONE

PART 2: CUSTOM PROCESSING ADJUSTMENT FACTOR CALCULATION

2.1 CUSTOM USER CLIENT ID	2.2 CUSTOM USER CLIENT NAME	2.3 CUSTOM VOLUMES

2.4 TOTAL CUSTOM VOLUMES	
2.5 TOTAL FACILITY COST CENTRE THROUGHPUT	
2.6 CUSTOM PROCESSING ADJUSTMENT FACTOR	%

Alberta
RESOURCE DEVELOPMENT

APPLICATION TO GRANDFATHER CO-GENERATION OR LONG-TERM CONTRACTS
GR1

PART 1: ROYALTY CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 CLIENT NAME

1.3 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.4 CONTACT PERSON

1.5 ( ) TELEPHONE

PART 2: DEDICATED RESERVES

2.1 STREAM ID

PART 3: CONTRACT INFORMATION

3.1 CONTRACT NO./ID

3.2 PARTIES TO CONTRACT

3.3 CONTRACT PRICE

PARTIES TO CONTRACT

3.4 BASIS FOR PRICE INCREMENTS

PARTIES TO CONTRACT

3.5 FREQUENCY OF PRICE INCREMENTS

PARTIES TO CONTRACT

3.6 TERM OF CONTRACT

3.7 EFFECTIVE DATE ☐☐☐☐☐☐☐☐ YR. MO. DY.

3.8 ☐ COPY OF CONTRACT ATTACHED

3.9 COLLATERAL AGREEMENTS (SPECIFY)

PART 4: CERTIFICATION

4.1 AUTHORIZED SIGNATURE

4.2 NAME OF CORPORATE SIGNING OFFICER

4.3 TITLE OF CORPORATE SIGNING OFFICER

4.4 DATE

[illegible]

Alberta
RESOURCE DEVELOPMENT

ANNUAL STATEMENT OF GRANDFATHERED CONTRACT SALES
GR2

PART 1: ROYALTY CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ☐ CONTRACT NO./ID

1.6 ______________________ CONTACT PERSON

1.7 (____)__________ TELEPHONE

PART 2: DETAILS OF CONTRACT SALES BY MONTH

DELIVERY MONTH	2.1 GJ's DELIVERED	2.2 CONTRACT SELLING PRICE ($/GJ)	2.3 NETBACK SELLING PRICE ($/GJ)
JANUARY			
FEBRUARY			
MARCH			
APRIL			
MAY			
JUNE			
JULY			
AUGUST			
SEPTEMBER			
OCTOBER			
NOVEMBER			
DECEMBER			
TOTAL		▨	▨

PART 3: CERTIFICATION

3.1 ______________________ AUTHORIZED SIGNATURE

3.2 ______________________ NAME OF CORPORATE SIGNING OFFICER

3.3 ______________________ TITLE OF CORPORATE SIGNING OFFICER

3.4 ______________________ DATE

09/01/99

Invoice Consolidation Concurrence Form
ICC1

Written concurrence (agreement) from all affected parties must be attached to the letter requesting Invoice Consolidation.

The Consolidator

Royalty Client ID

Name of Royalty Client

Authorized Signature

Title of Corporate Signing Officer

Name of Corporate Signing Officer

Date

(YYYYMM)
Effective Date of Consolidation

We agree to consolidate invoices produced under our client name and ID and understand the royalty implications of invoice consolidation.

The Consolidatee

Royalty Client ID

Name of Royalty Client

Authorized Signature

Title of Corporation Signing Officer

Name of Corporate Signing Officer

Date

(YYYYMM)
Effective Date of Consolidation

Effective the consolidation date, we agree that individual invoices will not be produced under our company name and understand the royalty implications of invoice consolidation.

*If multiple business associates are to be included in the consolidation, additional concurrences for each client are required.

'December 17, 1997

Alberta
RESOURCE DEVELOPMENT

NGL VALUATION AND TRANSPORTATION
NGL1

PART 1: DESIGNATED PURCHASER DETAIL

1.7 ☐ (CHECK IF YES) AMENDMENT

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ____________________ CLIENT NAME

1.3 PURCHASE YEAR/MONTH ☐☐☐☐☐☐ YR. MO.

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ____________________ CONTACT PERSON

1.6 (   ) ____________________ TELEPHONE

PART 2: REFERENCE PRICE INFORMATION

	PROPANE	BUTANE
2.1 VOLUMES ACQUIRED BASED ON EDMONTON PRICE (m^3)		
2.2 TOTAL ACQUISITION COST OF PRODUCT		
2.3 AVERAGE EDMONTON UNIT COST ($\$/m^3$)		

PART 3: TRANSPORTATION INFORMATION

		SPEC PRODUCT	NGL MIX	SPEC PENTANES
REGION 1	TRANSPORTATION VOLUMES (m^3)			
	AVERAGE TRANSPORTATION DIFFERENTIAL ($\$/m^3$)			
REGION 2	TRANSPORTATION VOLUMES (m^3)			
	AVERAGE TRANSPORTATION DIFFERENTIAL ($\$/m^3$)			
REGION 3	TRANSPORTATION VOLUMES (m^3)			
	AVERAGE TRANSPORTATION DIFFERENTIAL ($\$/m^3$)			
REGION 4	TRANSPORTATION VOLUMES (m^3)			
	AVERAGE TRANSPORTATION DIFFERENTIAL ($\$/m^3$)			

PART 4: CERTIFICATION

4.1 ____________________ AUTHORIZED SIGNATURE

4.3 ____________________ TITLE OF CORPORATE SIGNING OFFICER

4.2 ____________________ NAME OF CORPORATE SIGNING OFFICER

4.4 ____________________ DATE

03/01/96

Alberta
RESOURCE DEVELOPMENT

STORAGE COSTS
NGL2

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT

1.2 ______ CLIENT NAME

1.3 ☐☐☐☐☐☐☐☐ EUB FACILITY

1.4 ______ FACILITY NAME

1.5 PRODUCTION YEAR ☐☐☐☐

1.6 DATE PREPARED ☐☐☐☐☐☐☐☐ YR MO.

1.7 ______ CONTACT PERSON

1.8 (   ) ______ TELEPHONE

PART 2: STORAGE AREA INFORMATION

2.1 TOTAL ANNUAL VOLUMES STORED ☐ m^3

2.2 TOTAL ANNUAL INVOICED AMOUNT $ ☐

PART 3: CERTIFICATION

3.1 ______ AUTHORIZED SIGNATURE

3.2 ______ NAME OF CORPORATE SIGNING OFFICER

3.3 ______ TITLE OF CORPORATE SIGNING OFFICER

3.4 ______ DATE

11/01/99

OWNER ACTIVITY STATEMENT

PRIDE

	PROV.	TYPE	CODE	NAME
PROVINCE				
FACILITY				
OPERATOR				
OWNER				
ALLOCATOR				

PRODUCTION PERIOD	
FILING DATE	
OPERATOR CONTACT PERSON	
OPERATOR CONTACT PHONE NUMBER	
OPERATOR CONTACT FAX NUMBER	
OWNER CONTACT PERSON	
OWNER FAX NUMBER	

STREAM ID			STREAM CATEGORY	LOCATION			PRODUCT	ACTIVITY	QUANTITY		HEAT CONTENT		DESTINATION ID		
PROV.	TYPE	CODE		PROV.	TYPE	CODE			GROSS	NET	GROSS	NET	PROV.	TYPE	CODE

Page No.	1

Alberta
RESOURCE DEVELOPMENT

Facility Setup/Operator Change Form

When a change of facility operator occurs or when a new facility is activated, the Alberta Department of Energy - Gas Royalty Branch must be notified to ensure that the AEUB Documents will be processed and accepted under the new operator code.

FACILITY OPERATOR CHANGE

Facility Code	Facility Name Reason for Operator Change	From: Previous Operator Name Client ID and Name Contact Name and Phone Number	To: New Operator Name Client ID and Name Contact Name and Phone Number	Effective Date of Operator Change YY/MM

SETUP OF NEW FACILITY

New AUEB Assigned	Facility Name	Operator: Client ID and Name Contact Name and Phone Number	Legal Land Description	Facility Start Up Date YY/MM

In the case of an Injection Facility setup, change, or new scheme, an RMF3 form is required.
In the case of a Facility Cost Centre setup or change, an AC1 form is required.

SUBMITTED BY: ______________________ PHONE NUMBER: ______________
COMPANY: ______________________ DATE: ______________

NOTE: No retroactive processing of this document will be done without confirmation by the upstream operators (if any) of the change.

09/01/9

Alberta
RESOURCE DEVELOPMENT

MONTHLY STATEMENT OF PROPRIETARY GAS - ROYALTY WAIVED
PW1

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______ CLIENT NAME

1.3 PRODUCTION YEAR / MONTH ☐☐☐☐☐☐ YR. MO.

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ______ CONTACT PERSON

1.6 ( ) ______ TELEPHONE

PART 2: PROPRIETARY GAS DATA

2.1 PROJECT NAME	2.2 VOLUME OF GAS CONSUMED (10^3M^3)	2.3 HEAT CONTENT OF GAS CONSUMED (GJ)	2.4 DESIGNATED SOURCE	
			EUB FACILITY	STREAM ID
TOTAL				

PART 3: CERTIFICATION

3.1 ______ AUTHORIZED SIGNATURE

3.2 ______ NAME OF CORPORATE SIGNING OFFICER

3.3 ______ TITLE OF CORPORATE SIGNING OFFICER

3.4 ______ DATE

[illegible]

Alberta
RESOURCE DEVELOPMENT

CONSOLIDATED SINGLE WELL GROUP SETUP/CHANGE
RMF1

PART 1: CLIENT INFORMATION

1.1 ☐☐☐☐ OPERATOR ID 1.2 ______________________ OPERATOR NAME

1.3 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.4 ______________________ CONTACT PERSON

1.5 (____) ______________________ TELEPHONE

PART 2: WELL GROUP INFORMATION

2.1 ☐☐☐☐☐☐ WELL GROUP ID

2.2 UPDATE CODE ☐ (1) SETUP (2) CHANGE

2.3 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO.

2.4 TERMINATION DATE ☐☐☐☐☐☐ YR. MO.

PART 3: UNIQUE WELL IDS WITHIN A CONSOLIDATED SINGLE WELL GROUP

3.5 PAGE ____ OF ____

3.1 UPDATE CODE: (1) SETUP (2) CHANGE

CODE	3.2 UNIQUE WELL ID	3.3 EFFECTIVE DATE	3.4 TERMINATION DATE
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08/01/99

Alberta
RESOURCE DEVELOPMENT

CONSOLIDATED SINGLE WELL GROUP
SETUP/CHANGE
RMF1 (PART 3 CONTINUATION)

PART 3: UNIQUE WELL IDS WITHIN A CONSOLIDATED SINGLE WELL GROUP

3.5 PAGE ___ OF ___

3.1 UPDATE CODE: (1) SETUP (2) CHANGE

CODE	3.2 UNIQUE WELL ID	3.3 EFFECTIVE DATE	3.4 TERMINATION DATE
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Alberta
RESOURCE DEVELOPMENT

REASSIGNMENT OF VOLUMES
SETUP/CHANGE
RMF2

PART 1: CLIENT INFORMATION

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ____________________ CLIENT NAME

1.3 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.4 ____________________ CONTACT PERSON

1.5 (   ) ____________________ TELEPHONE

PART 2: CONCURRENCE

2.1 CONCURRENCE IS ATTACHED ☐ YES

IT IS THE RESPONSIBILITY OF THE ASSIGNOR SUBMITTING THIS FORM TO OBTAIN WRITTEN CONCURRENCE FROM ALL AFFECTED CLIENTS

PART 3: REASSIGNMENT OF VOLUMES FROM THE OWNER

3.1 STREAM ID ☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐ PROV TYPE CODE

3.2 ____________________ PRODUCT NAME

____________________ PRODUCT NAME

3.3 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO.

3.4 TERMINATION DATE ☐☐☐☐☐☐ YR. MO.

PART 4: REASSIGNMENT OF VOLUMES TO:

4.1 CLIENT ID	4.2 CLIENT NAME	4.3 ALLOCATION SHARE %
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	TOTAL	100%

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RESOURCE DEVELOPMENT

ACCEPTING/ASSIGNING VOLUME CONCURRENCE

Written concurrence (agreement) from all affected parties must be attached to the submitted RMF2 form.

Stream ID: ____________________
(Must be the same as 3.1 on the attached RMF2 form)

RMF2 Form Date Prepared: ____________________
(Must be the same as 1.3 on the attached RMF2 form)

Client ID

Name of Client *Assigning* the Volumes

Authorized Signature

Title of Corporate Signing Officer

Name of Corporate Signing Officer

Date

We agree to assign the volumes for the allocation share percentage specified under 4.3 on the attached RMF2 form **to** the client listed below.

Client ID

Name of Client *Accepting* the Volumes

Authorized Signature

Title of Corporate Signing Officer

Name of Corporate Signing Officer

Date

We agree to accept the volumes for the allocation share percentage specified under 4.3 on the attached RMF2 form **from** the client listed above.

[illegible]

Alberta
RESOURCE DEVELOPMENT

SINGLE WELL/INJECTION SCHEME SETUP/CHANGE
RMF3

PART 1: CLIENT INFORMATION

1.1 ☐☐☐☐ OPERATOR ID

1.2 ______________________ OPERATOR NAME

1.3 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.4 ______________________ CONTACT PERSON

1.5 (   ) ______________________ TELEPHONE

PART 2: WORKING INTEREST OWNERSHIP (W.I.O.)

2.1 STREAM ID ☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐☐ PROV TYPE CODE

2.2 UPDATE CODE ☐ (1) SETUP (2) CHANGE

2.3 ______________________ PRODUCT NAME

______________________ PRODUCT NAME

2.4 EFFECTIVE DATE ☐☐☐☐☐☐ YR. MO.

2.5 TERMINATION DATE ☐☐☐☐☐☐ YR. MO.

2.6 TOTAL CROWN % ☐☐☐☐☐☐☐☐☐☐

2.7 CLIENT ID	2.8 CLIENT NAME	2.9 W.I.O.%	2.10 CROWN %
	TOTAL	100%	

99/01/99

Alberta
RESOURCE DEVELOPMENT

SINGLE WELL/INJECTION SCHEME SETUP/CHANGE RMF3 (CONTINUATION)

PART 3: INJECTION SCHEME INFORMATION

3.1 ☐☐☐☐☐ SCHEME ID   3.2 ________________ NAME

3.3 ☐☐☐☐ INJECTION FACILITY ID   3.4 ________________ NAME

3.5 UPDATE CODE ☐ (1) SETUP (2) CHANGE   3.6 EFFECTIVE DATE ☐☐☐☐☐☐ YR MO.   3.7 TERMINATION DATE ☐☐☐☐☐☐ YR MO.

3.8 INJECTION SCHEME TYPE

☐ ENHANCED OIL RECOVERY SCHEME   ☐ CYCLING SCHEME   ☐ PRESSURE MAINTENANCE SCHEME

☐ COMMERCIAL STORAGE SCHEME   ☐ STORAGE SCHEME   ☐ OTHER ________________

3.9 CROWN INTEREST ☐☐☐☐☐☐☐☐☐☐

PART 4: UNIQUE WELL IDS WITHIN AN INJECTION SCHEME   4.6 PAGE ____ OF ____

4.1 FIELD/POOL CODE ☐   4.7 UNIT/WG CODE ☐

UPDATE CODE: (1) SETUP (2) CHANGE

4.2 UPDATE CODE	4.3 UNIQUE WELL ID	4.4 EFFECTIVE DATE	4.5 TERMINATION
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[illegible]

Alberta
RESOURCE DEVELOPMENT

SINGLE WELL/INJECTION SCHEME SETUP/CHANGE RMF3 (PART 4 CONTINUATION)

PART 4: UNIQUE WELL IDS WITHIN AN INJECTION SCHEME

4.6 PAGE ____ OF ____

4.1 FIELD/POOL CODE ☐

4.7 UNIT/WG CODE ☐

UPDATE CODE: (1) SETUP (2) CHANGE

4.2 UPDATE CODE	4.3 UNIQUE WELL ID	4.4 EFFECTIVE DATE	4.5 TERMINATION
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Alberta

RESOURCE DEVELOPMENT

ELECTION FOR GAS VALUATION
VA1

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ____________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐

1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ____________________ CONTACT PERSON

1.6 (____) ____________ TELEPHONE

1.7 CHECK ONE: ☐ INITIAL ☐ SUBSEQUENT

PART 2: VALUATION METHOD

2.1 CHECK ONE: ☐ REFERENCE PRICE ☐ CORPORATE AVERAGE PRICE

PART 3: ASSOCIATES

3.1 CLIENT ID	3.2 CLIENT NAME

PART 4: OFFICIAL DECLARATION

4.1 ____________________ AUTHORIZED SIGNATURE

4.3 ____________________ TITLE OF CORPORATE SIGNING OFFICER

4.2 ____________________ NAME OF CORPORATE SIGNING OFFICER

4.4 ____________________ DATE

[illegible]

Alberta
RESOURCE DEVELOPMENT

CORPORATE AVERAGE PRICE CALCULATION
GAS
VA2

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID   1.2 ____________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐   1.4 DATE PREPARED ☐☐☐☐☐☐☐☐ YR. MO. DY.

1.5 ____________ CONTACT PERSON   1.6 (   ) ____________ TELEPHONE

1.7 ☐ (CHECK IF YES) NO SALES/DISPOSITIONS

PART 2: ARM'S-LENGTH SALES

TYPE	2.1 TOTAL ANNUAL GJ's	2.2 GROSS ANNUAL REVENUE	TRANSPORTATION		2.5 NET ANNUAL REVENUE
			2.3 INTRA-ALBERTA	2.4 EXT-ALBERTA	
AGGREGATOR					
MARKETER					
PRODUCER					
END-USER					
SUBTOTAL					

PART 3: SALES TO ASSOCIATES (WITH A CAP)

3.1 CLIENT ID	3.2 CLIENT NAME	3.3 TOTAL GJ's	3.4 CAP	3.5 TOTAL REVENUE
SUBTOTAL	▨		▨	

PART 4: OTHER DISPOSITIONS

MONTH	4.1 TYPE 1	4.2 TYPE 2	4.3 TYPE 3	4.4 TOTAL GJ's	4.5 REFERENCE PRICE	4.6 TOTAL REVENUE
JAN						
FEB						
MAR						
APR						
MAY						
JUNE						
JULY						
AUG						
SEPT						
OCT						
NOV						
DEC						
SUBTOTAL					▨	

PART 5: CAP CALCULATION

5.1 $\frac{2.5 + 3.5 + 4.6}{2.1 + 3.3 + 4.4}$ = $ ________/GJ

PART 6: CERTIFICATION

6.1 ____________ AUTHORIZED SIGNATURE

6.3 ____________ TITLE OF CORPORATE SIGNING OFFICER

6.2 ____________ NAME OF CORPORATE SIGNING OFFICER

6.4 ____________ DATE

09/01/99

Alberta
RESOURCE DEVELOPMENT

ANNUAL CORPORATE AVERAGE PRICE CALCULATION
SULPHUR
VA3

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID
1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR ☐☐☐☐
1.4 DATE PREPARED ☐☐☐☐ | ☐☐ | ☐☐ YR. MO. DY.

1.5 ______________________ CONTACT PERSON
1.6 ( ) ______________________ TELEPHONE

1.7 ☐ (CHECK IF YES) NO SALES

PART 2: ARM'S-LENGTH SALES

2.1 POINT OF SALE	2.2 TONNES	2.3 GROSS ANNUAL REVENUE	2.4 TRANSPORTATION COSTS	2.5 STORAGE COSTS	2.6 NET ANNUAL REVENUE
NORTH AMERICA		▨	▨	▨	▨
OFF-SHORE		▨	▨	▨	▨
TOTAL					

PART 3: CERTIFICATION

3.1 ______________________ AUTHORIZED SIGNATURE
3.3 ______________________ TITLE OF CORPORATE SIGNING OFFICER

3.2 ______________________ NAME OF CORPORATE SIGNING OFFICER
3.4 ______________________ DATE

[illegible]

Alberta
RESOURCE DEVELOPMENT

MONTHLY CORPORATE AVERAGE PRICE CALCULATION
SULPHUR
VA4

PART 1: CLIENT DETAIL

1.1 ☐☐☐☐☐☐☐ CLIENT ID

1.2 ______________________ CLIENT NAME

1.3 PRODUCTION YEAR/MONTH ☐☐☐☐ ☐☐ YR. MO.

1.4 DATE PREPARED ☐☐☐☐ ☐☐ ☐☐ YR. MO. DY.

1.5 ______________________ CONTACT PERSON

1.6 (   ) ______________ TELEPHONE

1.7 ☐ (CHECK IF YES) NO SALES

PART 2: ARM'S-LENGTH SALES

2.1 POINT OF SALE	2.2 TONNES	2.3 GROSS MONTHLY REVENUE	2.4 TRANSPORTATION COSTS	2.5 STORAGE COSTS	2.6 NET MONTHLY REVENUE
NORTH AMERICA					
OFF-SHORE					
TOTAL					

PART 3: CERTIFICATION

3.1 ______________________ AUTHORIZED SIGNATURE

3.3 ______________________ TITLE OF CORPORATE SIGNING OFFICER

3.2 ______________________ NAME OF CORPORATE SIGNING OFFICER

3.4 ______________________ DATE

09/01/90

Alberta
RESOURCE DEVELOPMENT
GAS ROYALTY

REQUEST FOR REFUND

This form must be completed to request ongoing refunds of credit balances or to terminate a refund request.

Client Information

Client Name:	Client ID: ____________________ Gas Royalty Account: G94__________

Client Address for **refund** purposes: ______________________________
____
____
____

Is this a change to your address on record with the Department? yes_____ no _____

Signature of Financial Officer: ______________________	Phone Number: ______________
Name: ______________________________	Fax Number: ______________

Termination of Refund Request

Please terminate our refund request – credit balances are to remain in our account.	yes no

Refund Effective Date or Refund Termination Date: __________/__________/__________
Day Month Year

Note: This request will become effective upon receipt by the Department.

Refunds will be issued as follows:

1. **Direct Deposit – If banking information for your company is established with any Department of the Provincial Treasurer, refunds will be directly deposited to that account.**
2. **Cheque – If an account is not established, a cheque will be issued.**

Completed by (Contact Name): ______________________________ Phone Number: ____________________

Mail to:
Gas Royalty
Mineral Operations Division
8th Floor Petroleum Plaza North Tower
9945 108 Street
Edmonton, AB T5K 2G6

Alberta
RESOURCE DEVELOPMENT
GAS ROYALTY

VENDOR MAINTENANCE REQUEST FORM

Gas Royalty
Mineral Operations Division
8th Floor Petroleum Plaza North Tower
9945 108 Street
Edmonton, AB T5K 2G6

Date ______________________
Requested By_______________
Phone Number_______________

Statement of Direct Deposit to be mailed to:
Company Name ____
Address ____
____
____
____
____

Attach Void Cheque Here:

Alberta
RESOURCE DEVELOPMENT

OTHWERWISE FLARED SOLUTION GAS ROYALTY WAIVER PROGRAM

OSFG

APPLICATION FORM

Page 1 of ____

PART 1: CLIENT INFORMATION

1.1 ☐☐☐☐ Battery Operator ID

1.2 ______________________ Battery Operator Name

1.3 Date Prepared ☐☐☐☐☐☐☐☐ YR. MO. DAY

1.4 ______________________ Contact Person

1.5 (   ) ______________________ Telephone

PART 2: APPLICATION DETAIL

Please attach to this application the necessary supporting documentation as outlined in the instructions accompanying the application form.

PART 3: WELL IDENTIFIERS

Please use page 2 of this application form to describe the unique well identifier(s) that are, or will be, tied to the battery listed in field 3.1. Only wells associated with the conservation project described in Part 2 above are to be included.

PART 4: CERTIFICATION:

4.1 ______________________ AUTHORIZED SIGNATURE

4.2 ______________________ DATE

4.3 ______________________ NAME OF CORPORATE SIGNING OFFICER

4.4 ______________________ TITLE OF CORPORATE SIGNING OFFICER

PART 4: DEPARTMENT USE ONLY

Effective Billing Period ☐☐☐☐☐☐ YR. MO.

Date Received ☐

Apportionment Factor ☐.☐☐☐☐☐☐ (blank = 1.00000)

☐ EUB REASON CODE

RESOURCE DEVELOPMENT

OTHWERWISE FLARED SOLUTION GAS ROYALTY WAIVER PROGRAM OFSG APPLICATION FORM

Page __ of __

PART 3: Unique Well Identifiers

3.1 ☐☐☐☐☐☐☐☐ Battery ID

3.2 ☐☐☐☐ Field Code

3.3

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Department Use Only

Effective	Term Date

Alberta
RESOURCE DEVELOPMENT

GAS ROYALTY REGISTRY UPDATE

Please complete Part A and Part B and mail/fax to Department of Resource Development, Attn: Deen Khan, Fax # (780) 422-8732

PART A: Client Information

Is this an amended survey? Yes No

Client Information	
Client Name:	**Client ID:**
Client Address: **Is this a change to the address currently on record with the Department?** Yes No	
Senior Financial Officer Title: **Name:**	**Phone Number:** **Fax Number:**
Manager, Gas Royalty Accounting: **Name:**	**Phone Number:** **Fax Number:**

PART B: Reports Suppression:

Please indicate the reports which you would like to continue to receive by circling "yes" after the report name. If you no longer want to receive a repo then circle the "no" which follows the corresponding report name. Where a summary and detail version of a report is available, please indicate if you would like either or both versions of the report. Any reports that are not indicated will not be provided. Also, please indicate the format in which your company would like to receive the reports by circling "Paper" or "Electronically", and indicate whether this is a change in the way your company had previously received these forms by checking the box provided.

Reports				
Monthly Reports In what format does your company wish to receive the monthly reports? Paper or Electronically				Change? ☐
Crown Royalty Detail				Yes No
Low Productivity Calculation				Yes No
Annual Reports In what format does your company wish to receive the monthly reports? Paper or Electronically				Change? ☐
Annual Capital cost Allowance	Summar	Yes No	Detail	Yes No
Annual custom processing Fees net of Operating Costs	Summar	Yes No	Detail	Yes No
Corporate Effective Royalty Rate Calculation	Summar	Yes No	Detail	Yes No
The following reports are available in paper format only:				
Capital Cost Allowance Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement			Detail	Yes No
Custom Processing Fee Recapture for Enhanced Oil Recovery and Royalty Paid Bank Settlement			Detail	Yes No
Annual Capital Cost and Custom Processing Fee Adjustment			Detail	Yes No
Annual Allowable Cost Restriction Adjustment			Detail	Yes No
Royalty Deposit Adjustment			Detail	Yes No
Royalty Exemption Statement			Detail	Yes No

Completed by: ______________________ **Phone Number:** ____________________ **Date:** ____________________

Revised 2000-01-12